BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY

CASE NO. 2005-00341

DIRECT TESTIMONY
OF
TIMOTHY C MOSHER

ON BEHALF OF
KENTUCKY POWER COMPANY

September 26, 2005

DIRECT TESTIMONY OF
TIMOTHY C. MOSHER, ON BEHALF OF
KENTUCKY POWER COMPANY,
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
CASE NO. 2005-00341

Q. Please state your name, position and business address.

A. My name is Timothy C. Mosher. I am President and Chief Operating Officer of Kentucky Power Company (Kentucky Power or Company). My business address is address is 101 A Enterprise Drive, Frankfort, Kentucky 40602.

Q. Please summarize your educational background.

A. I received a Bachelor in Electrical Engineering degree from the University of Detroit in 1969 and an MBA from the University of Akron in 1974. In 1981 I attended an AEP Management Program at the University of Michigan. I also attended the Executive Program at the Darden Graduate School of Business Administration at the University of Virginia in 1995.

Q. Please describe your business experience.

A. I have spent my entire career as an employee of American Electric Power and its subsidiaries; I became President of Kentucky Power Company on June 1, 2004. Prior to that time I served as State President – Kentucky for American Electric Power from 1996-2004. Between 1974 and 1995 I served in various managerial and administrative positions with two subsidiaries of American Electric Power (Central Region Manager, Columbus Southern/Ohio Power Company, Zanesville, Ohio (1992-1995); Zanesville Division Manager, Ohio Power Company, Zanesville, Ohio (1989-1992); Marketing and Customer Services Manager, Ohio Power Company, Canton Division (1987-1989); Administrative Assistant

Governmental Affairs, Ohio Power Company (1981-1987); Area Manager, Ohio Power Company, Kenton, Ohio (1978-1981); Customer Engineering Services Manager, Ohio Power Company, Steubenville Division (1977-1978); Administrative Assistant – Industrial, Ohio Power Company, Canton General Office (1974-1977). I joined AEP in 1970 and worked as a power engineer for Ohio Power Company, Canton Division between 1970 and 1974.

Q. What are your main responsibilities as President of the Company?

A. My principal responsibility is to guide the management of the distribution operation of the Company. In that regard I work with and oversee the regulatory affairs, governmental/environmental affairs, business operations support, corporate communications and community affairs of the Company to ensure our corporate mission of providing reliable, timely service to our customers at the lowest practicable cost. I am responsible for assuring that the Company's obligations to our employees, the communities we serve and our shareholders are achieved. I also maintain relationships with the management teams responsible for the generation and transmission functions in Kentucky.

Q. Have you previously testified before the Kentucky Public Service Commission?

A. No. However, I have participated in several technical and informal conferences at the request of the Commission.

Q. What is the purpose of your testimony?

A. In my testimony I give an overview of the Company and its application to adjust its current rates to recover an additional $64.8 million annual revenue. I also will place the filing in its historical context and identify its major features. In addition

I will comment upon the Company's overall performance over the past several years.

Q. Please give a brief description of the Company and its operations.

A. Kentucky Power is a wholly owned subsidiary of American Electric Power, Inc. (AEP) and is engaged in the generation, purchase, transmission and distribution of electric power. The Company serves approximately 175,000 retail customers in parts of 20 eastern Kentucky counties. These customers are served through our distribution operations headquarters in Ashland, Kentucky (Cannonsburg), with satellite service centers in Hazard, Pikeville, and Whitesburg. The Company maintains a state office in Frankfort, Kentucky, which houses the office of the president, governmental/environmental affairs, corporate communications, business operations support and regulatory affairs functions. The Company supports the communities we serve through employee involvement and unrecoverable corporate contributions to organizations that foster community growth and education. The Company also sells electric power at wholesale to the City of Olive Hill and the City of Vanceburg. Exhibit TCM-1 is a map detailing the Company's service territory in Kentucky.

Q. Mr. Mosher why is Kentucky Power seeking to adjust its rates?

A. Despite increasing efficiencies, Kentucky Power's rates no longer permit the Company to recover the costs of providing reasonable service to its customers and to provide its shareholder with a fair and reasonable return. At least part of this is explained by the fact that Kentucky Power last filed for general rate relief as a base rate case in 1991, Case No. 91-066. The Settlement Agreement in that case produced a reduction in base retail electric rates of $11.5 million annually. In addition, as part of the settlement of its application for approval of the merger of Kentucky Power's parent and Central and South West Corporation, Kentucky Power agreed to a net merger savings credit that has resulted in $14,934,290 in reduced revenues since the merger credit became effective. Kentucky Power would have been forced to seek a general adjustment to its base rates much sooner in light of increasing environmental requirements but for its ability to recover some of those costs through the environmental cost recovery surcharge mechanism (Case No. 96-489; Case No. 2002-00169 and Case No.2005-00068.) Since the last general rate case, almost all of the Company's expenses have increased, including but not limited to; specialized safety equipment and wearables, computers and computerized systems for data collection, training programs, service vehicles, fuel for the vehicles, radio equipment, small hand tools, power tools, and employee costs including wages and healthcare benefits. Additionally, since the last base rate case the Company has made significant capital investments in distribution and transmission facilities in $90 million in a Unified Power Flow Control project approved by this Commission in 1998. These increased costs have reduced the Company's return on equity below acceptable levels. For the test year ended June 30, 2005 Kentucky Power's return on equity was 6.95%. By contrast, the allowed rate of return on equity in Case No. 96-489 was 11.5% while Case No. 2002-00169 had an allowed rate of return on equity of 11.0%. Case 2005-00068 approved September 7, 2005 by this Commission also has a rate of return on equity of 11.0%. We believe the cost information presented concerning our test year and the adjustments to those numbers justify the requested increase in this case.

Q. Would you provide a brief overview of the filing?

A. The Company is proposing to increase rates by approximately $64.8 million annually. This increase is based on adjusted data for the historic test year of twelve months ended June 30, 2005 and known and measurable changes occurring after the test year. The major components of the rate increase are as follows:

(a) Return on Common Equity of 11.5% in the amount of $26.4 Million

(b) Normalization of Point-to-Point Transmission Revenues in the amount of $9.6 Million

(c) Adjustment to the AEP Pool Capacity Cost in the amount of $9.0 Million

(d) Additional Reliability Spending in the amount of $6.8 Million

(e) Increased Depreciation Annualization in the amount of $4.7 Million

Q. What testimony is being filed by Kentucky Power in support of its application?

A. The Company's proposed adjustment to test year revenues, operating expenses, rate base and capitalization are sponsored by the witnesses and their respective subject areas listed below:

Errol Wagner: Annual Revenues, Adjustment to Test Year Capitalization, Test Year Revenues and Operating Expenses, Retail Jurisdiction Factors or Amounts, and Tariffs

Ranie Wohnhas: Test Year Results of Operations, Rate Case Adjustments to Net Electric Operating Income

Everett Phillips: Adjustment to Test Year Reliability Expenses

Jim Henderson: Depreciation Study

David Roush: Rate Design

Larry Foust: Class Cost of Service

Robert Bradish: Transmission Congestion Costs and PJM Administrative Costs

Dennis Bethel: Transmission Point-to-Point Revenues

Paul Moul: Return on Equity

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

COMMONWEALTH OF KENTUCKY

CASE NO. 2005-00341

COUNTY OF FRANKLIN

AFFIDAVIT

Timothy C. Mosher, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Timothy C. Mosher

Timothy C. Mosher

Subscribed and sworn before me by Timothy C. Mosher this 21st day of September 2005.

Judy K Jackett

Notary Public

My Commission Expires January 14, 2009

AEP Service Territory in Kentucky

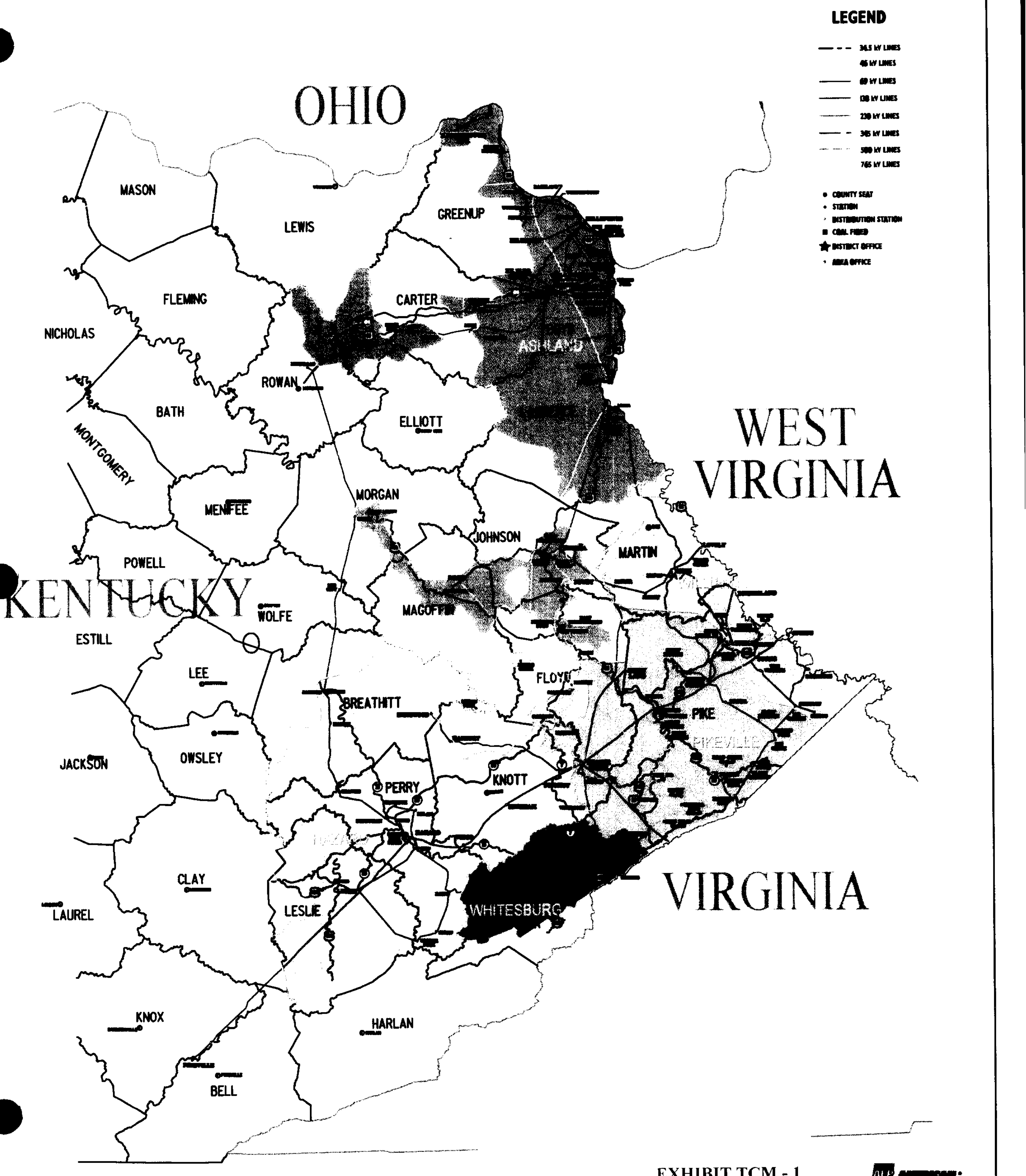

EXHIBIT TCM - 1

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY — CASE NO. 2005-00341

DIRECT TESTIMONY

OF

DENNIS W. BETHEL

ON BEHALF OF
KENTUCKY POWER COMPANY

September 26, 2005

INDEX TO DIRECT TESTIMONY OF
DENNIS W. BETHEL
CASE NO. 2005-00341

**DIRECT TESTIMONY OF
DENNIS W. BETHEL, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

I. Introduction and Background

Q. Please state your name and business address.

A. My name is Dennis W. Bethel. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by American Electric Power Service Corporation ("AEPSC" or "AEP"), as Managing Director – Regulated Tariffs.

Q. Please briefly describe your educational background and business experience.

A. In 1973, I earned a Bachelor of Science Degree in Electrical Engineering from the University of Evansville. I began my career with AEP that same year. Subsequently, I attended Ball State University, for a time, completing classes in finance, accounting, economics and business law. I have also attended a number of energy application and business training seminars, including the American Electric Power System Management Development Program at The Ohio State University. My first position with AEP was in energy applications as a Commercial and Industrial Engineer at Indiana Michigan Power Company ("I&M"). In 1977 I transferred to I&M's Rate Department, where I was responsible for the preparation of load research reports, development of class and jurisdictional cost-of-service studies, monthly fuel and purchased power adjustments, wholesale power contract administration, and rate design. In 1980 I transferred to the AEPSC Rate Research and Design Division. My responsibilities in AEPSC's Rate Department included supervision of projects relating to rate design, rate research, jurisdictional and class cost-of-service studies, load research, contracts, and special rate studies. In 1988, I transferred to the System Transactions Department where I was responsible for interconnection, power sales and transmission contract development and administration, rate studies and regulatory filings. In 1991 I was promoted to Manager – Interconnection Agreements. During this time I helped to develop and support AEP's first Open Access Transmission Tariff ("OATT") and rates for transmission and ancillary services filed in Docket No. ER93-540-000. In 1997 I was named Manager – Transmission Contracts and Regulatory Support in the System Operation Department. I was promoted to Director – Transmission and Interconnection Services in June 2000 and assumed my present position in June 2005.

Q. What are your duties and responsibilities as Managing Director – Regulated Tariffs?

A. In my present position I continue to have responsibility for the development and administration of transmission, interconnection and related tariffs and agreements, and participation in various activities related to AEP's memberships as a transmission owner in Regional Transmission Organizations ("RTOs"). Additionally, I now also have directional responsibility for retail and wholesale electric ratemaking, including the development of jurisdictional and class cost of service studies and rate design.

Q. Do you hold any professional licenses?

A. Yes, I am registered as a Professional Engineer in the States of Indiana and Ohio.

Q. Have you previously testified on electric rate issues before the KPSC or any other utility regulatory commissions?

A. Yes, I have presented testimony before the KPSC on electric cost-of-service and rate design issues. I have also testified before the Federal Energy Regulatory Commission ("FERC"), and the utility regulatory commissions of Michigan, Ohio, Tennessee, Virginia, and West Virginia.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

EXHIBIT	DESCRIPTION
Exhibit DWB-1	KPCo Projected 2006 Transmission Revenues
Exhibit DWB-2	KPCo Projected 2006 Net PJM Expansion Cost
Exhibit DWB-3	KPCo Projected Net RTO Start-up Costs

II. Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is three-fold, I support the calculation of (1) KPCo projected 2006 Network Integration Transmission Service (NTS) and Point-to-Point (PTP) Transmission Service revenues, (2) KPCo projected 2006 Net PJM Expansion Costs, and (3) KPCo projected 2006 Net PJM RTO Start-up Costs. My testimony and exhibits support going-level cost adjustments reflected in the cost-of-service, and shown in Section V, Workpaper S-4, pages 33, 35, 36 and 39.

III. PJM NTS and PTP Transmission Service Revenues

Q. Why is it necessary to adjust the test year levels of NTS and PTP revenues?

A. The NTS and PTP revenues, distributed to KPCo from those received by the AEP East Zone Companies for transmission services provided pursuant to PJM's FERC-approved Open Access Transmission Tariff (OATT) charges to non-affiliated parties, act as credits to reduce the cost of service for KPCo customers. On October 1, 2004 the AEP East Transmission System was integrated into the PJM RTO. This change, and the action of the FERC in Docket No. EL04-135-000 *et al* to eliminate charges for through and out (T&O) transmission service between PJM and the MidWest ISO (MISO), means that effective April 1, 2006 the AEP Companies, including KPCo, will experience a large reduction in PTP transmission revenues. The elimination of T&O charges between PJM and MISO actually occurred on December 1, 2004, but the FERC simultaneously implemented a temporary load-based lost revenue recovery mechanism known as Seams Elimination Cost Allocation (SECA) charges. The SECA charges will end as of April 1, 2006, causing KPCo's revenues from PTP transmission service to be reduced compared to those received during the Test Year.

Q. Is AEP taking any action to offset the loss of PTP revenue?

A. Yes. On March 31, 2005, AEP filed at the FERC for a two-step increase in the rates charged to PJM transmission customers that pay the AEP Zone transmission charges in the PJM OATT, who are those customers with load in AEP's Zone. The first step increase is scheduled to become effective on November 1, 2005. AEP asked for the second step to take effect when the SECA revenues end, expected to be April 1, 2006. The FERC encourages parties in such cases to attempt to reach a settlement in order to obtain reasonable results while avoiding the efforts and expense of litigation. Representatives of the actively participating parties, the FERC Staff, and KPSC, met during July, August and September. Pending revision of my testimony for any settlement results that are approved by FERC, I am proposing to use as the AEP Zone transmission revenue requirement and rates, charges which are higher than the PJM OATT that is presently in effect, and lower than the rates proposed by AEP to become effective April 1, 2006. The April 1, 2006 rates used in my exhibit represent approximately 75% of the increase proposed by AEP from the present rates.

Q. Please summarize the PJM PTP revenue projections contained in Exhibit DWB-1.

A. Exhibit DWB-1 estimates the share of PJM transmission revenues that KPCo might expect to receive in 2006, recognizing the PTP transaction levels that have occurred in PJM during the first seven months of 2005, and the increase in the allocation of revenue from PJM transactions to the AEP Zone that will result under the AEP transmission rate that I am using in this proceeding. The top block of numbers on lines 1 through 10 of Exhibit DWB-1, page 1, summarizes the Actual AEP Zone PTP Revenue Credits received from PJM for AEP In-Zone and PJM Border transactions during the period January 2005 through July 2005. The second block of numbers on lines 11 through 22 estimates the January through July, 2006 PJM PTP revenue credits that the AEP zone would receive given the January to July 2005 PJM transaction levels, the increase in the AEP Zone PTP rate for In-Zone transactions, and the increase in the AEP Zone's allocation of PJM Border transaction revenues, given the increase in the AEP Zone transmission revenue requirement I use. The third block of numbers on lines 23 through 34 estimates the

PTP revenue credits that the AEP Zone might receive from PJM in the remaining months of 2006 given the projected April 2006 transmission rate and revenue requirement increase, and assuming that the transaction levels in the months of August through December 2006 will equal the levels during the months of June through February of 2005, respectively. That is, the transaction levels in June are taken as a proxy for the transactions that might occur in August, May for September, April for October, March for November, and February for December.

Q. Why did you estimate August through December 2006 PJM PTP transactions by using June through February 2005 transactions as proxies?

A. PTP transactions are sensitive to power demand and the difference between generating capacity and load, that is, the amount of capacity reserves. Both of those parameters vary with weather, which is cyclical. The months of January and July tend to define the extremes of demand and weather, with the weather in the months I have matched up being reasonable proxies for one another.

Q. Why did you only use the PTP revenues during 2005 to create your estimate of annualized revenues?

A. I believe that the level of PJM PTP transactions during the last quarter of 2004 was likely to have been influenced by factors that do not exist in 2005 and will not exist in 2006. During October and November 2004, PJM was still permitted to charge its Border rate on T&O transactions to MISO, and it would have been difficult to obtain all the data from PJM needed to eliminate those transactions. Also during October, November and December 2004, PJM T&O transactions were assessed transitional surcharges that ceased to apply in 2005. These anomalies led me to the conclusion that the October through December 2004 data would not be a reliable indicator of PJM PTP transactions in those months of 2005 or 2006.

Q. Section V, Workpaper S-4, page 39 shows that KPCo received about $10.2 million in PTP revenues during the test year, yet your Exhibit DWB-1 supports only $460,461 of going-level PTP revenues. How do you explain the difference from historic levels?

A. Since the SECA revenues are going to be eliminated effective April 1, 2006, AEP and KPCo revenues from non-zone users of the AEP transmission system will fall precipitously on April 1, 2006. AEP has already experienced a decrease in such revenues as a result of the method used in PJM to allocate Border revenues, but, when the SECA revenues end, the AEP Zone will suffer a loss of transmission revenue of approximately $170 million per year. The going-level adjustment to reduce KPCo's annual transmission revenues by $9.6 million reflects KPCo's share of the AEP System loss.

Q. Please explain how you calculated the going-level network transmission service revenues.

A. The NTS revenue was calculated based on the AEP Zone NTS rate that I estimate will be effective April 1, 2006. Pursuant to PJM's transmission tariff, the NTS rate is charged to NTS customers daily on each MW of their Network Service Peak Load ("NSPL"). The NSPL that will be used in 2006 is not yet available, so it was necessary to use an estimate of the NSPL. For that estimate I used the 2005 NSPL of load serving entities in the AEP Zone other than the AEP Companies, e.g., third parties. PJM also charges the AEP Companies the same rate for NTS, but, since the

AEP Companies are allocated the revenues from the rate, those charges result in no net revenue to AEP. The estimated monthly third party NTS revenue was multiplied by KPCo's monthly projected AEP Member Load Ratio ("MLR") to determine KPCo's share of the projected revenue.

Q. What is the effect of your going-level adjustment for NTS revenues?

A. As shown by Section V, Workpaper S-4, page 33, my going-level adjustment for NTS revenues acts to decrease the KPCo retail cost of service by $1.6 million per year.

Q. Is AEP taking any other action to mitigate the loss of T&O and SECA revenues besides filing the transmission rate case you discussed earlier?

A. Yes. AEP has filed an appeal of the FERC decision to eliminate T&O transmission charges, however that appeal is presently being held in abeyance, pending the outcome of the SECA/Regional Rate Design proceeding. AEP also filed a protest of a January 2005 filing by certain PJM transmission owners proposing the continuation of zonal License Plate rates in PJM until at least February 2008. The FERC found merit in AEP's arguments, and opened a new complaint proceeding, Docket No. EL05-121-000, wherein PJM parties may file, by September 30, 2005, proposals to change the PJM transmission rate design. AEP noticed the FERC on September 1, 2005 that the AEP Companies would file a proposal to change the PJM rate design. In its filing, the AEP Companies will propose a change in the PJM transmission rate design that will provide compensation for use of AEP transmission by non-zone entities. If AEP is successful in obtaining post-SECA revenues under such a regional rate proposal, the incremental revenues would act to reduce AEP zonal costs in the future.

IV. PJM Expansion Expense Amortization Adjustment

Q. What costs are involved in the PJM expansion expense adjustment?

A. AEP, Commonwealth Edison and Dayton Power and Light Company (the "PJM West Companies"), as well as Dominion Virginia Power Company, contracted in 2002 with PJM to implement the expansion of PJM by integrating their transmission systems and control areas into PJM. The agreement required the PJM West Companies and Dominion to fund expenses incurred by PJM for the integration project, while PJM financed its capital costs. AEP's portion of the PJM expansion expenses, including carrying charges through June 30, 2005 at the FERC refund interest rate (as ordered by the FERC in Docket No. EL05-74-000) was $16.76 million, of which KPCo's share was approximately $1.14 million. Each of the AEP Companies deferred the PJM expansion expenses during the project, and began amortizing their respective shares of the cost in January 2005. KPCo's projected 2006 PJM expansion expense amortization is $170,076. The PJM West Companies requested recovery of their costs ($33.9 million for the three) over a ten-year period beginning May 1, 2005, through a charge on energy receipts by each LSE in the PJM region. The FERC denied the PJM West Companies' request to charge all PJM LSEs, and instead directed the Companies to file a compliance rate that recovers the costs from LSEs in the Companies' transmission zones. The PJM West Companies complied with the FERC order, but have also requested rehearing of the denial of PJM-wide recovery and the limitation of carrying charges to costs based on the FERC refund interest rate. The Compliance rate effective as of May 1, 2005 to recover the PJM expense reimbursements, including carrying costs, from LSEs in the AEP zone (including from AEP on behalf of its retail load) is $0.0156 per MWh. The rate is reflected in the PJM OATT as Schedule 13, Expansion Cost Recovery Charge (ECRC).

Q. How does the ECRC affect this case?

A. This method of calculating KPCo's net PJM Expansion cost reduces KPCo's cost by the net amount of revenues received from other entities.

Q. How did you calculate the projection of net 2006 PJM expansion costs for KPCo?

A. First, KPCo's projected pole-mile percentage allocated share of the 2006 ECRC charges on AEP LSE load was calculated. Then the projected 2006 revenue to be collected via the ECRC from all LSEs in the three PJM Zones was calculated, and KPCo's share of the ECRC revenues was determined. The AEP Companies receive 49.43% of the ECRC revenues while Commonwealth Edison and Dayton Power and Light receive the remainder. KPCo's share of the ECRC revenues was determined using its AEP transmission pole-mile allocation factor. Finally, KPCo's 2006 Net PJM Expansion cost was determined by netting the KPCo 2006 ECRC charges and revenues with the 2006 KPCo PJM Expansion expense amortization. Exhibit DWB-2 shows the details of the calculations I have just described, and supports the adjustment shown in Section V, Workpaper S-4, page 35.

V. Net RTO Formation And Start-up Costs

Q. What costs are involved in the RTO start-up cost adjustment?

A. The AEP Companies each shared in the costs to form and start an RTO in the AEP area. Some of the costs relate to early efforts to create a MidWest ISO, and some of the costs relate to AEP's integration into PJM, while the majority of the costs relate to Alliance RTO start up funding. Each of the companies that supported creation of the Alliance RTO funded an equal share of the approximately $100 million cost to advance the RTO from concept to test operations. The AEP Companies deferred their RTO formation and start-up costs, and in January 2005, pursuant to a letter order from the FERC, began amortizing their respective shares of the cost over 15 years. AEP included an estimate of the 2005 RTO start-up cost amortization in the cost-of-service supporting the transmission rates it proposed in Docket no. ER05-751, discussed earlier. My Exhibit DWB-3 calculates KPCo's net RTO start-up cost in a manner similar to that used to calculate the net PJM Expansion cost. First, the AEP and KPCo portions of the estimated PJM OATT charges for RTO start-up cost recovery for 2006 were calculated, with KPCo's share of the AEP charges being allocated based on transmission pole-miles. Then the estimated AEP Zone revenues under the PJM OATT for RTO start-up charges were calculated and KPCo's pole-mile ratio share determined. AEP's portion of the net RTO start-up cost, including carrying charges through June 30, 2005 was $17.2 million, of which KPCo's share was approximately $1.07 million. The net revenue to KPCo from start-up cost recovery charges acts to reduce the cost amortization that KPCo began in January 2005, and which is reflected at the going-level for a full year in the adjustment. The details of these calculations are shown in Exhibit DWB-3.

Q. Does this conclude your direct testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

STATE OF OHIO

CASE NO. 2005-00341

COUNTY OF FRANKLIN

AFFIDAVIT

DENNIS W. BETHEL, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Dennis W. Bethel
Dennis W. Bethel

Subscribed and sworn to before me by Dennis W. Bethel this 21st day of September, 2005.

Notary Public

My Commission Expires 05-18-08

NOTARIAL SEAL STATE OF OHIO

MANMOHAN K. SACHDEVA
Notary Public, State of Ohio
My Commission Expires 05-18-08

Kentucky Power Company
Point-to-Point Transmission Revenues at Going Level
Projected Post-SECA AEP OATT Rate Increase Effective 4/1/06

		Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	7 mos. Jan-Jul
1	**Actual PTP Rev Credits to AEP Zone**								
2	PJM Non-Firm PTP with POD in AEP Zone	$ 35,611	$ 3,849	$ 3,600	$ 16,235	$ 20,079	$ 31,480	$ 30,742	$ 141,595
3	PJM Firm PTP with POD in AEP Zone	$ 1,420	$ 1,420	$ 1,420	$ 1,420	$ 1,467	$ 16,789	$ 5,541	$ 29,476
4	In-Zone PTP Revenue Received (L2+L3)	$ 37,031	$ 5,269	$ 5,020	$ 17,655	$ 21,545	$ 48,269	$ 36,282	$ 171,072
5	PJM Firm PTP (Border Revenues)	$ 441,985	$ 277,755	$ 269,002	$ 224,128	$ 225,417	$ 224,635	$ 336,636	$ 1,999,559
6	PJM Non-Firm PTP (Border Revenues)	$ 230,034	$ 189,819	$ 248,281	$ 238,061	$ 247,432	$ 244,035	$ 264,051	$ 1,661,712
7	Border PTP Revenue Received (L5+L6)	$ 672,019	$ 467,574	$ 517,283	$ 462,189	$ 472,849	$ 468,670	$ 600,687	$ 3,661,270
8	Actual PTP Revenue Credits Jan - Jul 205	$ 709,050	$ 472,843	$ 522,303	$ 479,844	$ 494,394	$ 516,939	$ 636,969	$ 3,832,342
9	Actual % of PJM Point-to-Point Revenue To AEP	21.02106%	21.02106%	21.02106%	21.02106%	19.22946%	19.22946%	19.22946%	
10	% of Point-to-Point Revenue To AEP after April 1, 2006	23.42783%	23.42783%	23.42783%	23.42783%	23.42783%	23.42783%	23.42783%	

		Jan-06	Feb-06	Mar-06	Apr-05	May-06	Jun-06	Jul-06	7 mos. Jan-Jul
11	**Projected PTP Rev Credits to AEP Zone**								
12	PJM Non-Firm PTP with POD in AEP Zone	$ 40,662	$ 4,395	$ 4,111	$ 18,537	$ 22,926	$ 35,945	$ 35,102	$ 161,678
13	PJM Firm PTP with POD in AEP Zone	$ 1,621	$ 1,621	$ 1,621	$ 1,621	$ 1,675	$ 19,170	$ 6,327	$ 33,657
14	**In-Zone PTP Revenue at Est. 4/1/06 PTP Rate**	$ 42,283	$ 6,016	$ 5,732	$ 20,159	$ 24,601	$ 55,115	$ 41,428	$ 195,335
15	PJM Firm PTP (Border Revenues)	$ 492,589	$ 309,556	$ 299,801	$ 249,789	$ 274,633	$ 273,680	$ 410,134	$ 2,310,182
16	PJM Non-Firm PTP (Border Revenues)	$ 256,371	$ 211,552	$ 276,708	$ 265,317	$ 301,454	$ 297,315	$ 321,701	$ 1,930,417
17	**Border PTP Revenue with Est. 4/1/06 Rev. Req.**	$ 748,960	$ 521,108	$ 576,508	$ 515,106	$ 576,086	$ 570,995	$ 731,835	$ 4,240,599
18	**Going-Level AEP Zone PTP Rev @ Est. 4/1/06 Rates**	$ 791,243	$ 527,124	$ 582,240	$ 535,265	$ 600,687	$ 626,110	$ 773,263	$ 4,435,934
19	AEP LSE Percentage	86%	86%	86%	86%	86%	86%	86%	
20	**AEP LSE Portion of Zonal PTP Revenue**	$ 680,469	$ 453,327	$ 500,727	$ 460,328	$ 516,591	$ 538,455	$ 665,006	$ 3,814,903
21	**KPCo MLR**	**0.07538**	**0.07389**	**0.07389**	**0.07389**	**0.07389**	**0.07389**	**0.07392**	
22	**KPCo PTP Revenue Share**	**$ 51,292**	**$ 33,495**	**$ 36,998**	**$ 34,013**	**$ 38,170**	**$ 39,785**	**$ 49,156**	**$ 282,909**

		Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	5 mos. Aug-Dec	Year Total
23	**Projected PTP Rev Credits to AEP Zone**							
24	PJM Non-Firm PTP with POD in AEP Zone	$ 35,945	$ 22,926	$ 18,537	$ 4,111	$ 4,395	$ 85,914	$ 247,592
25	PJM Firm PTP with POD in AEP Zone	$ 19,170	$ 1,675	$ 1,621	$ 1,621	$ 1,621	$ 25,709	$ 59,366
26	**In-Zone PTP Revenue at Est. 4/1/06 PTP Rate**	$ 55,115	$ 24,601	$ 20,159	$ 5,732	$ 6,016	$ 111,623	$ 306,958
27	PJM Firm PTP (Border Revenues)	$ 273,680	$ 274,633	$ 249,789	$ 299,801	$ 309,556	$ 1,407,459	$ 3,717,641
28	PJM Non-Firm PTP (Border Revenues)	$ 297,315	$ 301,454	$ 265,317	$ 276,708	$ 211,552	$ 1,352,345	$ 3,282,762
29	**Border PTP Revenue with Est. 4/1/06 Rev. Req.**	$ 570,995	$ 576,086	$ 515,106	$ 576,508	$ 521,108	$ 2,759,804	$ 7,000,403
30	**Going-Level AEP Zone PTP Rev @ Est. 4/1/06 Rates**	$ 626,110	$ 600,687	$ 535,265	$ 582,240	$ 527,124	$ 2,871,427	$ 7,307,361
31	AEP LSE Percentage	86%	86%	86%	86%	86%		
32	**AEP LSE Portion of Zonal PTP Revenue**	$ 538,455	$ 516,591	$ 460,328	$ 500,727	$ 453,327	$ 2,469,427	$ 6,284,330
33	**KPCo MLR**	**0.07213**	**0.07183**	**0.07183**	**0.07183**	**0.07183**		**0.07327**
34	**KPCo PTP Revenue Share**	**$ 38,840**	**$ 37,109**	**$ 33,068**	**$ 35,970**	**$ 32,565**	**$ 177,552**	**$ 460,461**

Exhibit DWB-1
Page 1 of 2

Kentucky Power Company
Network Transmission Revenues at Going-Level
Projected Post-SECA AEP OATT NTS Rate Effective 4/1/06

Month	Days	Non-Affiliate NTS Billing Demand		Monthly Revenue @ Est. 4/1/06 Rate	KPCo MLR		KPCo Share NTS Revenue
January	31	3,119.22	$	5,154,497	0.07538		388,536
February	28	3,119.22	$	4,655,674	0.07389		343,998
March	31	3,119.22	$	5,154,497	0.07389		380,854
April	30	3,119.22	$	4,988,222	0.07389		368,569
May	31	3,119.22	$	5,154,497	0.07389		380,854
June	30	3,119.22	$	4,988,222	0.07389		368,569
July	31	3,119.22	$	5,154,497	0.07392		381,011
August	31	3,119.22	$	5,154,497	0.07213		371,810
September	30	3,119.22	$	4,988,222	0.07183		358,329
October	31	3,119.22	$	5,154,497	0.07183		370,273
November	30	3,119.22	$	4,988,222	0.07183		358,329
December	31	3,119.22	$	5,154,497	0.07183		370,273
Total	365	37,430.64	$	60,690,040	0.07318	$	4,441,405

Kentucky Power Company
Summary of PJM Expansion Expense, Amortization, Revenue, and Charges Under PJM Schedule 13
Projected for 2006

2006	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec	Total
AEP GWH (Page 2)	11,342	9,854	10,137	8,974	9,360	10,229	10,986	10,913	9,302	9,527	9,697	11,376	121,699
AEP ECRC @$0.0156/MWh	$ 176,937	$ 153,726	$ 158,143	$ 140,001	$ 146,009	$ 159,576	$ 171,378	$ 170,250	$ 145,114	$ 148,619	$ 151,278	$ 177,473	$ 1,898,504
KP Pole Miles Percentage	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	
KP ECRC	**$ 11,943**	**$ 10,377**	**$ 10,675**	**$ 9,450**	**$ 9,856**	**$ 10,771**	**$ 11,568**	**$ 11,492**	**$ 9,795**	**$ 10,032**	**$ 10,211**	**$ 11,979**	**$ 128,149**
ComEd Zone GWH (Page 2)	9,015	8,027	8,099	7,493	7,887	9,127	10,484	10,374	8,378	7,919	7,750	8,649	103,202
Dayton Zone GWH (Page 2)	1,690	1,494	1,533	1,354	1,405	1,556	1,721	1,697	1,455	1,413	1,448	1,622	18,388
AEP Zone GWH (Page 2)	13,159	11,423	11,749	10,400	10,835	11,861	12,733	12,660	10,773	11,041	11,261	13,221	141,117
Total GWH	23,864	20,944	21,381	19,247	20,127	22,544	24,938	24,731	20,606	20,373	20,459	23,492	262,707
PJM ECRC @ $0.0156/MWh	$ 372,279	$ 326,730	$ 333,540	$ 300,253	$ 313,981	$ 351,683	$ 389,030	$ 385,801	$ 321,461	$ 317,822	$ 319,167	$ 366,479	$ 4,098,226
AEP ECRC Revenue @ 49.43%	$ 184,018	$ 161,503	$ 164,869	$ 148,415	$ 155,201	$ 173,837	$ 192,298	$ 190,701	$ 158,898	$ 157,099	$ 157,764	$ 181,151	$ 2,025,754
KP Pole Miles Percentage	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	
KP ECRC Revenue	**$ 12,421**	**$ 10,901**	**$ 11,129**	**$ 10,018**	**$ 10,476**	**$ 11,734**	**$ 12,980**	**$ 12,872**	**$ 10,726**	**$ 10,604**	**$ 10,649**	**$ 12,228**	**$ 136,738**
Net ECRC Adjustment	**$ (478)**	**$ (524)**	**$ (454)**	**$ (568)**	**$ (620)**	**$ (963)**	**$ (1,412)**	**$ (1,380)**	**$ (931)**	**$ (572)**	**$ (438)**	**$ (249)**	**$ (8,589)**
KP Deferred PJM Amort In TY	$ 14,161	$ 14,161	$ 14,173	$ 14,173	$ 14,173	$ 14,173	$ -	$ -	$ -	$ -	$ -	$ -	$ 85,014
KP Deferred PJM Amortization	$ 14,173	$ 14,173	$ 14,173	$ 14,173	$ 14,173	$ 14,173	$ 14,173	$ 14,173	$ 14,173	$ 14,173	$ 14,173	$ 14,173	$ 170,076
Net Amortization Adjustment	**$ 12**	**$ 12**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 14,173**	**$ 14,173**	**$ 14,173**	**$ 14,173**	**$ 14,173**	**$ 14,173**	**$ 85,062**
KP Net Expense	**$ 13,695**	**$ 13,649**	**$ 13,719**	**$ 13,605**	**$ 13,553**	**$ 13,210**	**$ 12,761**	**$ 12,793**	**$ 13,242**	**$ 13,601**	**$ 13,735**	**$ 13,924**	**$ 161,487**

Exhibit DWB-2
Page 1 of 2

Projected AEP Load
Based on PJM Load Forecast for 2006
GWh

Year	Month	AEP * Zonal Energy (1)	AEP LSE 5-CP Share (2)	AEP LSE Load (3=1x2)	Agent for 5-CP Share (4)	Agent for Load (5=1x4)	AEP Load (6=3-5)	Mon. Power Load (7)	AEP Revised Load (8=6+7)
2006	January	13,159	0.88	11,557	0.03	377	11,180	162	11,342
2006	February	11,423	0.88	10,032	0.03	327	9,705	149	9,854
2006	March	11,749	0.88	10,318	0.03	336	9,982	156	10,137
2006	April	10,400	0.88	9,134	0.03	298	8,836	139	8,974
2006	May	10,835	0.88	9,516	0.03	310	9,205	154	9,360
2006	June	11,861	0.88	10,417	0.03	340	10,077	152	10,229
2006	July	12,733	0.88	11,182	0.03	365	10,818	168	10,986
2006	August	12,660	0.88	11,118	0.03	363	10,756	158	10,913
2006	September	10,773	0.88	9,462	0.03	309	9,153	149	9,302
2006	October	11,041	0.88	9,697	0.03	316	9,381	146	9,527
2006	November	11,261	0.88	9,890	0.03	322	9,568	130	9,697
2006	December	13,221	0.88	11,611	0.03	379	11,233	144	11,376
	Total	141,117		123,933		4,041	119,892	1,807	121,699

Year	Month	ComEd * Zonal Energy (9)	Dayton * Zonal Energy (10)
2006	January	9,015	1,690
2006	February	8,027	1,494
2006	March	8,099	1,533
2006	April	7,493	1,354
2006	May	7,887	1,405
2006	June	9,127	1,556
2006	July	10,484	1,721
2006	August	10,374	1,697
2006	September	8,378	1,455
2006	October	7,919	1,413
2006	November	7,750	1,448
2006	December	8,649	1,622
	Total	103,202	18,388

* Zonal Load GWHs from PJM 2005 Load Forecast Table C-2, page 52 for calendar year 2006.

Kentucky Power Company
Projected Monthly 2006 Net RTO Formation Costs
RTO Formation Charges and Revenues under PJM OATT, and KPCo RTO Stat-Up Cost Amortization

2006	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec	Total
RTO Formation Cost Recovery													
AEP-East Zone Load (Page 2)	24,267	24,267	24,267	24,267	24,267	24,267	24,267	24,267	24,267	24,267	24,267	24,267	
AEP RTO Formation Cost Amortization	$ 196,849	$ 196,848	$ 196,850	$ 196,849	$ 196,847	$ 196,850	$ 196,848	$ 196,848	$ 196,849	$ 196,850	$ 196,848	$ 196,849	$ 2,362,185
KP Pole Miles Percentage	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	
KPCo RTO Formation Cost Recovery	**$ 13,287**	**$ 13,287**	**$ 13,287**	**$ 13,287**	**$ 13,287**	**$ 13,287**	**$ 13,287**	**$ 13,287**	**$ 13,287**	**$ 13,287**	**$ 13,287**	**$ 13,287**	**$ 159,444**
RTO Formation Expense													
AEP LSE Load (Page 2)	20,660	20,660	20,660	20,660	20,660	20,660	20,660	20,660	20,660	20,660	20,660	20,660	
AEP RTO Formation Cost Share	$ 167,590	$ 167,589	$ 167,591	$ 167,590	$ 167,588	$ 167,591	$ 167,589	$ 167,589	$ 167,590	$ 167,591	$ 167,589	$ 167,590	$ 2,011,074
KP Pole Miles Percentage	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	
KPCo RTO Formation Expense	**$ 11,312**	**$ 11,312**	**$ 11,312**	**$ 11,312**	**$ 11,312**	**$ 11,312**	**$ 11,312**	**$ 11,312**	**$ 11,312**	**$ 11,312**	**$ 11,312**	**$ 11,312**	**$ 135,744**
Net RTO Formation Cost Revenue Adjustment	**$ 1,975**	**$ 1,975**	**$ 1,975**	**$ 1,975**	**$ 1,975**	**$ 1,975**	**$ 1,975**	**$ 1,975**	**$ 1,975**	**$ 1,975**	**$ 1,975**	**$ 1,975**	**$ 23,700**
Amortization Expense													
KPCo Amortization Expense	$ 12,187	$ 12,187	$ 12,187	$ 12,187	$ 12,187	$ 12,187	$ 12,187	$ 12,187	$ 12,187	$ 12,187	$ 12,187	$ 12,187	$ 146,244
KPCo NET RTO Start-Up Cost Amortization	**$ 10,212**	**$ 10,212**	**$ 10,212**	**$ 10,212**	**$ 10,212**	**$ 10,212**	**$ 10,212**	**$ 10,212**	**$ 10,212**	**$ 10,212**	**$ 10,212**	**$ 10,212**	**$ 122,544**

Exhibit DWB-3
Page 1 of 2

Projected Monthly 2006
AEP East Zone Peak Load
MW

Year	Month	AEP Zonal * Load (1)	AEP LSE 5-CP Share (2)	AEP LSE Load (3=1x2)	Agent for 5-CP Share (4)	Agent for Load (5=1x4)	AEP Load (6=3-5)	Mon. Power Load (7)	AEP Revised Load (8=6+7)
2006	January	22,915	0.88	20,124	0.03	656	19,468	250	19,718
2006	February	22,568	0.88	19,820	0.03	646	19,174	251	19,425
2006	March	20,594	0.88	18,086	0.03	590	17,496	240	17,737
2006	April	18,718	0.88	16,439	0.03	536	15,903	236	16,139
2006	May	19,017	0.88	16,701	0.03	545	16,156	267	16,423
2006	June	22,333	0.88	19,614	0.03	640	18,974	274	19,248
2006	July	23,978	0.88	21,058	0.03	687	20,371	289	20,660
2006	August	23,341	0.88	20,499	0.03	668	19,830	285	20,115
2006	September	21,864	0.88	19,202	0.03	626	18,576	262	18,837
2006	October	18,292	0.88	16,064	0.03	524	15,541	230	15,771
2006	November	20,001	0.88	17,565	0.03	573	16,993	231	17,223
2006	December	21,926	0.88	19,256	0.03	628	18,628	240	18,868

2006	Zonal Peak	23,978
	Mon Power	289
	Rev. Zonal	24,267

* AEP System-East Zonal MW Load from PJM 2005 Load Forecast Table B-6, page 40 for calendar year 2006.

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY

CASE NO. 2005-00341

DIRECT TESTIMONY
OF
ROBERT W. BRADISH

ON BEHALF OF
KENTUCKY POWER COMPANY

September 26, 2005

DIRECT TESTIMONY OF
ROBERT W. BRADISH
FOR KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
CASE NO. 2005 - 00341

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DIRECT TESTIMONY OF
ROBERT W. BRADISH
FOR KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
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I. Introduction

Q. Please state your name and business address.

A. My name is Robert W. Bradish. My business address is 155 West Nationwide Boulevard Suite 500, Columbus, Ohio 43215.

Q. Please indicate by whom you are employed and in what capacity.

A. I am the Vice President – Market Operations and an employee of American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP). AEP is the parent company of Kentucky Power Company (KPCo).

Q. Please briefly describe your educational background and business experience.

A. I received a Bachelor of Science – Electrical Engineering degree in May 1985, and a Master of Science – Electrical Engineering degree in December 1987, both from the Clarkson University. I also received a Master of Business Administration degree from The Ohio State University in May 2001. I was employed by AEPSC in 1987 as an assistant engineer and progressed through several engineering grades to the senior engineer level. In 2001, I was promoted to Manager -Power and Transmission Market Analysis, Director in 2002, Vice President - Transmission and Market Analysis in 2003, and my current position in 2005.

Q. Have you previously submitted testimony in any regulatory proceedings?

A. Yes. I have previously filed testimony before the Oklahoma Corporation Commission as set forth in Cause Nos. PUD 200300633, PUD 200300634 and PUD 200300076 and before the Michigan Public Service Commission as set forth in Case No.U-13919-R.

II. Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my direct testimony is to identify and support test year expenses (12 months ended June 30, 2005) and the forecasted 2006 monthly costs and revenues from PJM Interconnection, LLC (PJM) for implicit congestion, Financial Transmission Rights (FTRs), net operating reserves and net ancillary services (synchronous condensing, reactive supply and blackstart), which I collectively refer to as the "PJM Costs and Revenues". These PJM Costs and Revenues are associated with serving Kentucky Power Company (KPCo) retail customers. I also support the schedules and adjustments associated with the development of the PJM Costs and Revenues and propose a tracking mechanism as a means of recovering certain of these costs.

My direct testimony will provide the monthly 2006 forecasted amounts for KPCo. The PJM Costs and Revenues were allocated to KPCo by applying the appropriate Member Load Ratio (MLR) in accordance with the terms of the AEP Interconnection Agreement. MLRs are fully explained by Witness Wagner in his direct testimony.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

RWB Exhibit 1	KPCo PJM Monthly Test Year (Revenues)/ Expenses
RWB Exhibit 2	KPCo Forecasted Monthly 2006 Net Congestion Costs
RWB Exhibit 3	KPCo Forecasted Monthly 2006 Net Other Costs or Revenues
RWB Exhibit 4	KPCo Forecasted Monthly 2006 Net Ancillary Services
RWB Exhibit 5	KPCo Forecasted Monthly 2006 PJM Administrative Fees

III. Forecasted Monthly 2006 Net Congestion Costs

Locational Marginal Pricing

Q. Please describe the concept of Locational Marginal Pricing (LMP).

A. LMP is the method PJM utilizes to assign prices to the points, or nodes, making up the PJM market. PJM runs a market simulation every five minutes where it uses generation offers to sell and load offers to buy, combined with a security constrained economic dispatch tool, to calculate LMP for each of the nodes (source and sink points) within the market model. The source point is the generation source and the sink point is the delivery or load point. The LMP represents the cost of serving one additional megawatt (MW) of load at each of the nodes represented in the market model. The difference in LMP between sources and sinks represents the incremental cost of using the transmission system to supply load from a given set of resources. The higher the level of constraint between generation and the load, the higher the difference in LMPs between the source of generation and the sink point.

Q. Please describe the concept of congestion costs in PJM.

A. Congestion costs in PJM are simply the difference between what a load pays for energy and what a generator supplying the load receives for the energy it produces.

If there were no congestion on any transmission line in PJM, the LMP would be the same for all generators and loads across the entire PJM market region. However, when transmission lines become constrained, LMPs vary across the entire region and the price for energy paid by the load is different than the price received for energy produced by the generator.

Q. Does PJM consider LMPs in dispatching the system?

A. Yes. PJM runs its Energy Management System to solve for the most economical combination of units to supply the load, taking into consideration physical limitations (constraints) of the transmission system. This is called a Security Constrained Economic Dispatch. Congestion costs occur when higher cost out-of-merit generation must be dispatched in lieu of available lower cost generation to avoid transmission system overloads.

Q. Please explain out-of-merit dispatch.

A. PJM continually monitors the loading conditions on the transmission lines and facilities. If certain transmission lines are being loaded beyond their normal operating limits, PJM will re-configure generator output to raise the output of generation in locations that will aid in reducing the power flows on the constrained transmission element. This generation can be of higher cost, increasing the cost to serve load near the constraint and creating higher LMPs. This difference in LMPs is what creates the financial measurement of congestion.

Q. How are congestion costs derived?

A. In its very simplest form, congestion costs are derived by calculating the difference in the LMP between the generation source and the delivery point.

Q. Are there different kinds of congestion?

A. Yes. PJM congestion costs are made up of both explicit and implicit congestion. I will describe the differences below.

Explicit and Implicit Congestion

Q. Please explain explicit congestion.

A. Explicit congestion measures the difference in LMPs between two specific points on the power system. Explicit congestion applies when a Market Participant schedules a transaction between two distinct points.

Q. Please provide an example of explicit congestion.

A. Assume that a Market Participant wants to purchase 100 MWs from one node (the source node) and schedule the power to another node (the sink node) on the PJM system. After PJM runs the Security Constrained Economic Dispatch, it determines the LMP for the source node is \$20/megawatt-hour (MWh) and the LMP for the sink node is \$30/MWh. The cost differential represents the higher cost of generation that must be dispatched in the sink node in lieu of available lower cost generation to avoid transmission system overloads. The explicit congestion charge is \$10/MWh. Explicit congestion costs are associated with off-system sales and are accounted for in the System Sales Clause Tariff.

Q. How does this differ from implicit congestion?

A. Implicit congestion is a measure of congestion costs between a portfolio of generation resources and the loads they serve. Implicit congestion is the difference between 1) the price paid to PJM by the Load Serving Entities (LSEs) in serving their load and 2) the price paid by PJM to the generators which are used as energy resources to serve the load. The price paid by the LSEs is the load-weighted average LMP price for all the nodes in the LSEs territory. The price paid to the generators is the energy-weighted average for all the generation nodes used to serve the LSEs territory.

Q. Please provide an example of implicit congestion costs.

A. As a simple example, if the average LMP for the AEP load zone is $45/MWh and the average of the generation sources available to the load is $30/MWh, then the implicit congestion charge owed to PJM is $15/MWh.

Q. What are the test year implicit congestion costs for KPCo?

A. KPCo's implicit congestion costs for nine months of the test year were $4,597,608, as shown in RWB Exhibit 1. These are the actual costs incurred by KPCo for the twelve months ended June 30, 2005, as no actual costs were incurred during the first three of these twelve months that occurred prior to AEP joining PJM.

Q. What are the 2006 forecasted implicit congestion costs for KPCo?

A. RWB Exhibit 2 provides the implicit congestion costs that were forecasted for AEP and then allocated to KPCo for 2006 on a monthly basis. This exhibit shows that implicit congestion costs for KPCo is forecasted to be $4,958,940 in 2006.

Q. How were the 2006 implicit congestion costs forecasted?

A. The forecasted implicit congestion costs were based on an annualization of nine months of actual history ending June 30, 2005 that KPCo has experienced since joining PJM.

Financial Transmission Rights

Q. Please explain the concept of FTRs.

A. When PJM introduced the congestion charge concept, they did not want to penalize customers who had purchased firm transmission service on the PJM system (both network and point-to-point transmission service). To achieve this objective, PJM developed the concept of FTRs to help transmission customers offset the incremental costs associated with congestion. FTRs are designed to protect LSEs from the uncertainty associated with congestion charges.

Q. Please explain the rights associated with FTRs.

A. FTRs are financial contracts that entitle the holder to a stream of revenues or charges based on the hourly energy price differences across a transmission path between the FTR source and the FTR sink. LSEs can hedge the congestion cost risk across a transmission path by choosing FTRs that offset the congestion charges. FTRs grant the FTR holder the right to collect the revenues associated with congestion in the day-ahead market between specific points. PJM collects congestion charges from the Market Participants and then distributes these funds to the FTR holders. The after-the-fact value of the FTR is defined by the difference between the Sink LMP and the Source LMP (LMP Sink – LMP Source). Therefore, if the LMP at the source (generator) is higher than the LMP of the sink, the FTR may actually have a negative value, resulting in the FTR holder paying PJM.

FTRs are designed to offset the cost of congestion between the sources and the loads. However, there are several factors that may change throughout the course of a year to create a difference between congestion costs and FTR revenues. For example:

- FTR values are based on the day-ahead LMPs, while congestion costs are based on both day-ahead LMPs and any deviation from the day-ahead schedule multiplied by real-time LMPs.
- The FTRs must be chosen by the LSE for an entire year. However, changes in transmission configuration, generating unit retirements and additions, and changes in load distribution patterns can happen anytime during the year, and will have an effect on the value of LMPs.
- The congestion charges collected by PJM meant to fund the FTRs may not equal the FTR revenue targets for the entire PJM region. In these cases, PJM allocates the cost of the under-funding among all FTR holders.

Q. How does an LSE such as AEP obtain an FTR?

A. During each PJM planning year (June through the following May) AEP is allocated an amount of FTRs equivalent to its load that occurs at the time of the PJM RTO peak hour. AEP must then choose the best combination of FTRs to manage the financial congestion risk for serving the AEP load. Once the awards are made by PJM, AEP is not allowed to change the FTR selections until the beginning of the next planning year (June). This process will continue through May 2007.

Q. Is AEP guaranteed to receive all the FTR combinations requested?

A. No. PJM runs a simultaneous feasibility test for the AEP requests, along with requests from other LSEs. PJM will grant FTR requests along transmission paths to the extent such requests do not violate security constraints. This keeps participants from requesting more MWs of FTRs over a transmission line than it could feasibly handle.

Q. Is there a way to secure more FTRs once the planning year starts?

A. Yes. PJM holds monthly auctions that allow market participants to buy and sell FTRs along congested transmission paths. However, it is difficult to make significant changes to the allocated portfolio of FTRs in these monthly auctions because the most valuable FTRs are usually taken in the annual allocation process.

Q. What are the test year FTR revenues for KPCo?

A. KPCo's total FTR revenues for nine months of the test year were $4,287,874 as shown in RWB Exhibit 1. These are the actual credits received by KPCo based on the MLR allocation of the total for the twelve months ended June 30, 2005.

Q. What are the forecasted FTR revenues for KPCo in 2006?

A. RWB Exhibit 2 provides the FTR revenues that were forecasted for AEP and were allocated to KPCo for 2006 on a monthly basis. This exhibit shows that KPCo is forecasted to receive a credit of $7,961,292 in 2006.

Q. How were the 2006 FTR revenues forecasted?

A. In order to forecast the FTR revenues, I started with the current allocation of FTRs which AEP was awarded beginning June 1, 2005. Next I took the historical pricing for all the nodes in the AEP System for the period starting with AEP joining PJM in October 2004 through the end of June 2005. I then applied the historical prices to the most recent FTRs allocated to AEP to estimate the FTR revenues. Finally, I annualized the FTR revenues based on the data for the nine months.

Auction Revenue Rights

Q. Is the FTR allocation process that you explained above going to change in the future?

A. Yes, the process will change beginning in June 2007.Q. Please explain how the FTR allocation process will change beginning in June 2007.

A. Beginning in June 2007, AEP will be allocated Auction Revenue Rights (ARRs) in place of the current FTR allocation. The number of ARRs and the method for obtaining them are similar to the FTR allocation process.

ARRs are entitlements allocated annually to Firm Transmission Service Customers that entitle the holder to receive an allocation of the revenues from the Annual FTR auction. Therefore, it allows the holder of the entitlement to monetize the value of the FTR through selling the rights of the associated FTR to another entity during the annual auction. So, if the ARR holder believes that the auction price for the associated FTR is higher than the expected value of the actual FTR when congestion is cleared by the PJM market, the holder may sell the FTR in the auction and lock in the revenues over the next twelve months. The holder of the ARR also has the option to directly convert the ARR into FTRs and use them in the manner described in the FTR section above.

Q. Will the two methods for managing congestion (FTRs and ARRs) produce a similar result?

A. Yes. If the holder of the ARR does not sell the entitlement, the results would be similar. The holder of the ARR may also sell the FTR entitlement with an expectation to get additional value from the entitlement as described above. Therefore, the ARRs will essentially take the place of FTRs.

Q. Are you making an estimate of the magnitude of the potential revenue of ARRs in your 2006 forecast?

A. No. At this time AEP has not been credited any revenues associated with ARRs.

Q. Please explain the concept of net congestion costs.

A. Net congestion cost is the difference between congestion costs and revenues from FTRs and Auction Revenue Rights (ARRs). Basically, congestion costs are incurred when there are constraints on the transmission paths between the generation resources (source) and the load delivery point (sink). FTRs and ARRs are financial entitlements that can be used to assist in mitigating these costs. I will further explain this below.

Q. What are the 2006 forecasted net congestion costs for KPCo?

A. RWB Exhibit 2 provides the net congestion costs that were forecasted for AEP and were allocated to KPCo for 2006 on a monthly basis. This exhibit shows that KPCo is forecasted to receive a credit $3,002,352 in 2006.

IV. Cost Recovery Tracking Mechanism

Q. Should FTR revenue and implicit congestion costs be included in base rates?

A. No. I propose that a tracking mechanism be implemented to recover the cost of FTR revenues and implicit congestion costs. FTR revenues and implicit congestion costs exhibit tremendous volatility on a monthly basis. This approach would minimize risk for both KPCo and the retail customers of KPCo. Beginning in June 2007, I propose that ARR revenues be included in the tracking mechanism as well.

Q. How will the tracking mechanism function?

A. The tracking mechanism is explained in the direct testimony of Witness Roush.

V. Forecasted Monthly 2006 Net Operating Reserve Charges

Q. Please describe operating reserve charges.

A. Operating reserve charges in PJM provide for make-whole payments to generators that are called on by PJM but which do not receive sufficient revenues from the energy market to cover their bids. PJM may call on these units either day-ahead or in real-time.

For example, after the daily bids are cleared at 1600 Eastern Prevailing Time, PJM may determine that additional generation should be brought on line for the next day for reliability purposes due to changes in weather, generation forced outages, or projected transmission facility overloads. PJM will call on these units and pay them for their start-up costs as well as their operating costs throughout the time they are requested to run by PJM. The costs incurred for these expenses are called operating reserves. According to the PJM Operating Agreement, the owner of generation which is scheduled by PJM under these conditions is guaranteed to be made whole for the day based on the owner's bids in the market.

Q. Please explain the difference between day-ahead and real-time operating reserves.

A. Day-ahead operating reserve costs arise when PJM makes operating decisions for commitment of additional generating units between 1200 and 2400 on the day prior to the operating day. Real-time operating reserve costs arise when PJM makes a similar decision once the operating day has begun.

Q. Does KPCo presently pay for operating reserves as part of their East Central Area Reliability Council (ECAR) requirements?

A. No, they do not. Operating reserves in PJM are significantly different than operating reserves in ECAR. Operating reserves in ECAR deal with spinning and system regulation services and are based on a percentage of forecasted daily peak loads. The costs associated with the ECAR operating reserves are already included in the existing KPCo rates, and these costs will continue to be incurred in the future. The PJM operating reserves are in addition to the ECAR operating reserves and the costs associated with providing such reserves are not included in current rates.

Q. Please explain the difference between ECAR operating reserves and the PJM operating reserves?

A. The ECAR operating reserves are a static amount of generation based only on a percentage of peak load that must be able to produce energy within a given time period and able to provide system regulation. The PJM operating reserves are based on day-ahead and real-time regional needs for operating reserves due to operational considerations, the additional need takes into consideration the existence of the ECAR operating reserves.

Q. How are the PJM operating reserve charges collected?

A. The Day-ahead operating reserves charges are collected by PJM from the LSEs and other market participants in proportion to the cleared day-ahead MW demand bids. The real-time, or balancing, operating reserves charges are collected from the LSEs and other market participants in proportion to real-time deviations from day-ahead scheduled quantities.

Q. Do AEP generating units collect operating reserve revenues?

A. Yes they do. When PJM calls on AEP units to run as described above, AEP is paid for start-up and operating costs. The amount provided in the 2006 forecast is the net of costs collected from AEP by PJM and revenues paid to AEP by PJM.

Q. What are the test year PJM operating reserve expenses for KPCo?

A. KPCo's total operating reserve expenses for nine months of the test year were $997,123, as shown in RWB Exhibit 1. These are the actual costs incurred by KPCo on an MLR allocated basis for the twelve months ended June 30, 2005.

Q. What is the 2006 forecasted amount for operating reserves?

A. The 2006 forecasted expense is $1,495,680 for KPCo as shown in RWB Exhibit 3.

Q. How were these expenses forecasted for 2006?

A. Since these expenses have not exhibited a monthly pattern and are only partially related to weather and fuel prices, the forecast was solely based on an annualization of nine months of actual history ending June 30, 2005 that KPCo experienced since joining PJM.

Q. How were these expenses allocated to KPCo?

A. The PJM bill to AEP was for the entire AEP System and these costs were allocated to KPCo using the MLR methodology.

VI. Forecasted Monthly 2006 Net Ancillary Services

Q. Please describe what the PJM net ancillary service costs include.

A. KPCo has incurred incremental PJM Costs and Revenues for net synchronous condensing, net reactive supply and net blackstart services.

Q. Please explain the need for these ancillary services.

A. Ancillary services are necessary to support the transmission of capacity and energy from generating resources to loads, while maintaining reliable operation of the transmission system.

Synchronous Condensing Service

Q. Please explain synchronous condensing service.

A. Synchronous condensing is an ancillary service charge that is incurred when PJM must pay for a unit to spin its turbine without producing any energy. This may occur when PJM needs a combustion turbine to be available to come on line instantaneously for spinning reserves, system reliability, reactive power and economic energy.

Q. Why is AEP charged for this service?

A. As part of the PJM system, AEP must share the costs in keeping the PJM system reliable according to the PJM operating agreement.

Q. What are KPCo's test year expenses for synchronous condensing services?

A. KPCo's total expense for synchronous condensing services for nine months of the test year was $259,350. These shown in RWB Exhibit 1 and are the actual costs incurred by KPCo on an allocated MLR basis for the twelve months ended June 30, 2005.

Q. What is the 2006 forecasted amount for synchronous condensing service?

A. The 2006 forecasted amount is a charge of $444,600 for KPCo and is included in RWB Exhibit 4.

Q. How were these costs forecasted for 2006?

A. Since these expenses have not exhibited a monthly pattern and are only partially related to weather and the price of fuel, the forecast was based on an annualization of nine months of actual history ending June 30, 2005 that KPCo experienced since joining PJM.

Q. How were these expenses allocated to KPCo?

A. PJM bills AEP on a total company basis and these costs were in turn allocated to KPCo using the MLR methodology.

Reactive Supply Service

Q. Please explain reactive supply service.

A. All transmission customers, including those that use network service to serve internal load, must purchase reactive supply service from PJM. Reactive supply service is required to maintain transmission voltages within acceptable PJM reliability limits. These charges are based on annual revenue requirements filed by generating units with the FERC and are not market based.

The generation owners are paid monthly for reactive supply service based on their annual revenue requirement. These revenue requirements are allocated first to point-to-point transmission customers based on MWs reserved, with the remaining revenue requirement allocated to the zonal network customers based on monthly peak loads. Each transmission zone has its own reactive supply service rate.

PJM may also assess reactive supply service charges to LSEs if there is a need to reduce MW output from a generation source to provide additional reactive supply service support (a generator may have to reduce MW output to provide more reactive supply service output). This is a real-time incremental expense rather than an annual revenue requirement. Further, PJM assesses these daily charges to Network Service customers in the zone which requires the increased reactive supply service support. Any generator may receive FERC approved reactive supply service revenue within the AEP control area.

Q. Why is AEP charged for reactive supply service?

A. Although AEP can self supply its required reactive supply service, several companies have constructed generating units within the AEP control area in the last few years. Under the PJM rules for settling service charges, AEP must pay for reactive supply service charges, as described above, for all the units that have FERC approved reactive supply service revenue rights within the AEP control area.

Q. What are KPCo's test year expenses for reactive supply services?

A. KPCo's total expense for reactive supply services for nine months of the test year was $230,260. These shown in RWB Exhibit 1 and are the actual costs incurred by KPCo on an allocated MLR basis for the twelve months ended June 30, 2005.

Q. What is the 2006 forecasted amount for reactive supply service charges?

A. The 2006 forecasted amount is a charge of $394,728 for KPCo and is included in RWB Exhibit 4. The amount provided in the 2006 forecast is the net of costs collected from AEP by PJM and revenues paid to AEP by PJM.

Q. How were these costs forecasted for 2006?

A. AEP does not anticipate much variability from historical amounts. Therefore, the 2006 forecast was based on an annualization of nine months of actual history ending June 30, 2005 that KPCo experienced since joining PJM.

Q. How were these expenses allocated to KPCo?

A. PJM bills AEP on a total company basis and these costs were in turn allocated to KPCo using the MLR methodology.

Blackstart Service

Q. Please explain blackstart service.

A. All transmission customers must purchase blackstart service from PJM. Blackstart service is required to ensure that the power grid can restart following a complete system blackout. The critical units needed for system restoration are compensated for the costs incurred in maintaining blackstart service capability. These charges are derived from annual revenue requirements that are submitted by the generators providing the service and approved by the PJM Market Monitoring Unit and are not market-based costs.

Q. Please explain the costs included for blackstart service.

A. Blackstart service costs are comprised of fixed costs, variable operations and maintenance costs, training costs, fuel storage and carrying costs for each critical generating unit. These costs are then increased by a ten percent incentive factor.

Q. Why should AEP incur a net cost for these services?

A. PJM and North American Electric Reliability Council (NERC) require blackstart service capability within a control area. To the extent that other generators within the AEP control area have blackstart service capability, AEP is required to pay a share of the other generators' formula costs.

Q. How are blackstart service costs allocated to the LSEs?

A. The zonal rates are based on the blackstart service capability within that zone. The total blackstart service costs are first collected from point-to-point transmission customers based on monthly peak usage. The remaining costs in each zone are then collected from network customers serving load in that zone based on monthly peak loads. Hence, it is similar to the reactive supply service charge calculation.

Q. What are KPCo's test year expenses for blackstart services?

A. KPCo's total expense for blackstart services for nine months of the test year was $7,427. These are shown in RWB Exhibit 1 and are the actual costs incurred by KPCo on an allocated MLR basis for the twelve months ended June 30, 2005.

Q. What is the 2006 forecasted amount for blackstart service charges?

A. The 2006 forecasted amount is a charge of $12,732 for KPCo and is included in RWB Exhibit 4. The amount provided in the 2006 forecast is the net of costs collected from AEP by PJM and revenues paid to AEP by PJM.

Q. How were these costs forecasted for 2006?

A. AEP does not anticipate much variability from historical amounts. Therefore, the 2006 forecast was based on an annualization of nine months of actual history ending June 30, 2005 that KPCo experienced since joining PJM.

Q. How were these expenses allocated to KPCo?

A. PJM bills AEP on a total company basis and these costs were in turn allocated to KPCo using the MLR methodology.

VII. Forecasted Monthly 2006 PJM Administrative Fees

Q. What are the types of PJM administration fees that are included in RWB Exhibit 5?

A. As a Transmission Provider, PJM assesses each of its market participants monthly administration fees to recover PJM operating costs. These fees are filed with the Federal Energy Regulatory Commission (FERC). The five components of these administration fees are: Control Area Administration Service, Financial Transmission Rights (FTR) Administration Service, Market Support Service, Regulation and Frequency Response Administration Service and Capacity Resource and Obligation Management Service. PJM also charges a FERC Annual Charge Recovery fee to recover its annual assessment of FERC fees.

Q. What is Control Area Administration Service and how is it billed?

A. Control Area Administration Service comprises all of the activities of PJM associated with preserving the reliability of the PJM Region and administering point-to-point transmission service and network integration transmission service. This service is billed based on MWhs of energy delivered.

Q. What is FTR Administration Service and how is it billed?

A. The FTR Administration Service comprises all of the activities of PJM associated with administering FTRs, including coordination of FTR bilateral trading, administration of FTR auctions, support of PJM's online, internet-based eFTR tool, and FTR award analyses. FTR Administration Service is billed based on three components:

- The quantity in MWhs of all FTRs held by the market participant. PJM computes the charge for this component by multiplying the quantity of FTR MWhs times the tariff rate.
- The number of hours in all bids to buy FTR obligations during the annual auction and all monthly auctions, multiplied by the tariff rate.
- Five times the number of hours in all bids to buy FTR options during the annual auction and all monthly auctions, multiplied by the tariff rate.

Q. What is meant by your reference to the eFTR tool?

A. PJM provides and maintains online applications that provide members with access to a continuous flow of real-time data to assist with making business decisions and managing their daily transactions. Specifically, eFTR provides for management of the FTR process as described earlier in my testimony. It is one of a suite of electronic (reference "e") tools that facilitate the necessary data exchange to support the operation of the RTO.

Q. What is Market Support Service and how is it billed?

A. Market Support Service comprises all of the activities of PJM associated with supporting the operation of the PJM Interchange Energy Market and related functions, including market modeling and scheduling functions, locational marginal pricing support, market settlements and billing, support of PJM's internet-based customer interactive tool known as eSchedules, and market monitoring. PJM bills each user of Market Support Service a charge equal to the sum of the following components:

- MWhs of energy delivered to load in the PJM Region or for export, plus MWhs of energy input into the transmission system, plus MWhs of all accepted increment and decrement bids. PJM computes the charge for this component by multiplying the quantity of MWhs times the tariff rate.
- The number of bid/offer segments submitted during the period. A bid/offer segment is each price/quantity pair submitted into the day-ahead energy market. PJM computes the charge for this component by multiplying the quantity of bid/offer segments times the tariff rate.

Q. What is Regulation and Frequency Response Administration Service and how is it billed?

A. Regulation and Frequency Response Administration Service comprises all of the activities of PJM associated with administering the provision of regulation and frequency response service. Regulation and frequency response are necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled frequency at sixty cycles per second (60 Hz). The obligation to maintain this balance between resources and load lies with PJM, the Transmission Provider. PJM administration costs associated with the provision of Regulation and Frequency Response Administration Service are billed to Load Serving Entities (LSEs) and regulating generators based on MWhs of regulation.

Q. What is Capacity Resource and Obligation Management Service and how is it billed?

A. This service comprises the activities of PJM associated with assuring that customers have arranged for sufficient generating capacity to meet their installed capacity obligations; administering the capacity credit market in the PJM region; supporting PJM's internet-based eCapacity tool; and providing technical support such as long-term load forecasting, studies to establish reserve requirements and the determination of each LSE's capacity obligations. This service is billed to LSEs, generators and eCapacity users based on the MW-days of resource or obligation provided.

Q. What is the FERC Annual Charge Recovery fee and how is it billed?

A. PJM, as a public utility and Transmission Provider, is subject to an annual charge assessed by the FERC to cover the costs of that agency. PJM bills this charge to transmission customers based on their total MWhs of electric energy delivered.

Q. What are KPCo's test year expenses for PJM administration fees?

A. KPCo's total expense for PJM administration fees for nine months of the test year was $2,215,551. These shown in RWB Exhibit 1 and are the actual costs incurred by KPCo on an allocated MLR basis for the twelve months ended June 30, 2005.

Q. How did you calculate the 2006 forecast of PJM administration fees for AEP?

A. From its inception as an independent system operator, and later as an RTO, PJM has recovered its administration costs through FERC-approved formula rates that provide for automatic recovery of all of PJM's expenses. Since 2001, the rates for those administration costs have been unbundled into the five categories discussed above (the FERC Annual Charge Recovery Fee is an administration cost of the FERC, not PJM). Under this rate structure, PJM fees for Control Area Administration Service are automatically adjusted monthly and fees for the other services are adjusted annually. Rather than filing formula rates for 2006, PJM on July 1, 2005 filed with the FERC a stated rate that eliminates annual adjustments and establishes an ongoing rate that would change only if and when the FERC permits a rate change in response to a subsequent PJM rate filing, a request by customers, or upon the FERC's own initiative. The monthly 2006 forecast of KPCo PJM administration fees is shown in RWB Exhibit 5 and was developed based on the AEP nine-month history of PJM billing determinants, the resulting average cost per MWh and the PJM stated rate filed with FERC.

Q. Please explain how the PJM Administration Fees were developed?

A. AEP's membership in PJM since October 2004 provides a nine-month history of billing determinants for each of the previously described categories. The total charges associated with the billing determinants was calculated and divided by the actual MWhs for the nine-month period to determine an average cost per MWh. The same calculations were performed using the PJM stated rate, which resulted in an average cost per MWh that would have occurred if the new stated rates were in effect. The proportional difference between the stated rate cost per MWh and the historical cost per MWh (an increase of 19.5%) was multiplied by the test year administration fees and annualized. This resulted in a forecast of KPCo 2006 PJM administration fees of $3,529,848, or a monthly amount of $294,154 as shown in RWB Exhibit 5.

Q. Should operating reserve charges, net ancillary service costs and PJM administrative fees be included in the tracker mechanism?

A. No, they should not. Operating reserve charges, net ancillary service costs and PJM administrative fees are anticipated to remain stable corresponding to historical averages and are therefore more appropriately placed in base rates.

Q. Does this conclude your testimony?

A. Yes it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

STATE OF OHIO

CASE NO. 2005-00341

COUNTY OF FRANKLIN

AFFIDAVIT

Robert W Bradish, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Robert W. Bradish

Subscribed and sworn to before me by Robert W. Bradish this 16 day of September, 2005.

Notary Public

My Commission Expires January 4, 2009

NOTARIAL SEAL STATE OF OHIO

DONNA J. STEPHENS
Notary Public, State of Ohio
My Commission Expires 01-04-09

RWB Exhibit 1

KPCo PJM Monthly Test Year (Revenues) / Expenses

2006 (Revenue) / Expense	Jul	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	2006 Total
PJM Implicit Congestion	$ -	$ -	$ -	$ 260,683	$ 167,192	$ 889,823	$ 986,232	$ 474,176	$ 145,739	$ 299,854	$ 659,383	$ 714,526	$ 4,597,608
PJM FTR Revenue	$ -	$ -	$ -	$ (59,238)	$ (177,232)	$ (483,005)	$ (573,604)	$ (732,773)	$ 83,344	$ (347,233)	$ (501,351)	$ (1,496,781)	$ (4,287,874)
PJM Operating Reserve	$ -	$ -	$ -		$ (123,076)	$ 229,951	$ 134,619	$ 124,741	$ 130,580	$ 136,100	$ (11,875)	$ 376,082	$ 997,123
PJM Net Synchronous Condensing	$ -	$ -	$ -			$ 118,434	$ 72,459	$ 21,475	$ 33,640	$ 10,266	$ 14,236	$ (11,160)	$ 259,350
PJM Net Reactive Supply	$ -	$ -	$ -			$ 36,929	$ (5,263)	$ 38,197	$ 56,107	$ 18,193	$ 44,858	$ 41,239	$ 230,260
PJM Net Blackstart	$ -	$ -	$ -			$ 1,308	$ 2	$ 2,881	$ 1,978	$ 1,249	$ (154)	$ 163	$ 7,427
PJM Administrative Fees	$ -	$ -	$ -	$ 225,924	$ 230,904	$ 243,851	$ 260,773	$ 252,236	$ 311,050	$ 234,611	$ 228,439	$ 227,763	$ 2,215,551
Total KPCo PJM Test Year (Revenues) / Expenses	$ -	$ -	$ -	$ 427,369	$ 97,789	$ 1,037,290	$ 875,219	$ 180,932	$ 762,437	$ 353,039	$ 433,537	$ (148,167)	$ 4,019,444

RWB Exhibit 2

KPCo Forecasted Monthly 2006 Net Congestion Costs

2006 (Revenue) / Expense	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2006 Total
FTR Revenue Forecast for 2006													
AEP FTR Revenues	$ (8,949,703)	$ (8,949,703)	$ (8,949,703)	$ (8,949,703)	$ (8,949,703)	$ (8,949,703)	$ (8,949,703)	$ (8,949,703)	$ (8,949,703)	$ (8,949,703)	$ (8,949,703)	$ (8,949,703)	$ (107,396,436)
KPCo MLR	0.07413	0.07413	0.07413	0.07413	0.07413	0.07413	0.07413	0.07413	0.07413	0.07413	0.07413	0.07413	
KPCo FTR Revenues	$ (663,441)	$ (663,441)	$ (663,441)	$ (663,441)	$ (663,441)	$ (663,441)	$ (663,441)	$ (663,441)	$ (663,441)	$ (663,441)	$ (663,441)	$ (663,441)	$ (7,961,292)
Implicit Congestion Cost Forecast for 2006													
AEP Implicit Congestion Costs	$ 5,574,600	$ 5,574,600	$ 5,574,600	$ 5,574,600	$ 5,574,600	$ 5,574,600	$ 5,574,600	$ 5,574,600	$ 5,574,600	$ 5,574,600	$ 5,574,600	$ 5,574,600	$ 66,895,200
KPCo MLR	0.07413	0.07413	0.07413	0.07413	0.07413	0.07413	0.07413	0.07413	0.07413	0.07413	0.07413	0.07413	
KPCo Implicit Congestion	$ 413,245	$ 413,245	$ 413,245	$ 413,245	$ 413,245	$ 413,245	$ 413,245	$ 413,245	$ 413,245	$ 413,245	$ 413,245	$ 413,245	$ 4,958,940
Net Congestion Costs													
AEP System	$ (3,375,103)	$ (3,375,103)	$ (3,375,103)	$ (3,375,103)	$ (3,375,103)	$ (3,375,103)	$ (3,375,103)	$ (3,375,103)	$ (3,375,103)	$ (3,375,103)	$ (3,375,103)	$ (3,375,103)	$ (40,501,236)
KPCo Operating Company	$ (250,196)	$ (250,196)	$ (250,196)	$ (250,196)	$ (250,196)	$ (250,196)	$ (250,196)	$ (250,196)	$ (250,196)	$ (250,196)	$ (250,196)	$ (250,196)	$ (3,002,352)

(1) AEP will be allocated Auction Revenue Rights beginning in June 2007.

RWB Exhibit 3

KPCo Forecasted Monthly 2006 Net Other Costs or Revenues

2006 (Revenue) / Expense	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2006 Total
PJM Operating Reserve	$ 124,640	$ 124,640	$ 124,640	$ 124,640	$ 124,640	$ 124,640	$ 124,640	$ 124,640	$ 124,640	$ 124,640	$ 124,640	$ 124,640	$ 1,495,680
Total KPCo Net Other New Costs or Revenues	$ 124,640	$ 124,640	$ 124,640	$ 124,640	$ 124,640	$ 124,640	$ 124,640	$ 124,640	$ 124,640	$ 124,640	$ 124,640	$ 124,640	$ 1,495,680

KPCo Forecasted Monthly 2006 Net Ancillary Services

2006 (Revenue) / Expense	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2006 Total
PJM Net Synchronous Condensing	$ 37,050	$ 37,050	$ 37,050	$ 37,050	$ 37,050	$ 37,050	$ 37,050	$ 37,050	$ 37,050	$ 37,050	$ 37,050	$ 37,050	$ 444,600
PJM Net Reactive Supply	$ 32,894	$ 32,894	$ 32,894	$ 32,894	$ 32,894	$ 32,894	$ 32,894	$ 32,894	$ 32,894	$ 32,894	$ 32,894	$ 32,894	$ 394,728
PJM Net Blackstart	$ 1,061	$ 1,061	$ 1,061	$ 1,061	$ 1,061	$ 1,061	$ 1,061	$ 1,061	$ 1,061	$ 1,061	$ 1,061	$ 1,061	$ 12,732
Total KPCo Net Ancillary Services	$ 71,005	$ 71,005	$ 71,005	$ 71,005	$ 71,005	$ 71,005	$ 71,005	$ 71,005	$ 71,005	$ 71,005	$ 71,005	$ 71,005	$ 852,060

RWB Exhibit 5

KPCo Projected Monthly 2006 PJM Administrative Fees

2006 (Revenue) / Expense	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2006 Total
PJM Administrative Fees	$ 294,154	$ 294,154	$ 294,154	$ 294,154	$ 294,154	$ 294,154	$ 294,154	$ 294,154	$ 294,154	$ 294,154	$ 294,154	$ 294,154	$ 3,529,848
Total KPCo PJM Administrative Fees	$ 294,154	$ 294,154	$ 294,154	$ 294,154	$ 294,154	$ 294,154	$ 294,154	$ 294,154	$ 294,154	$ 294,154	$ 294,154	$ 294,154	$ 3,529,848

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY

CASE NO. 2005-00341

DIRECT TESTIMONY
OF
LARRY C FOUST

ON BEHALF OF
KENTUCKY POWER COMPANY

September 26, 2005

DIRECT TESTIMONY OF
LARRY C. FOUST, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2005-00341

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DIRECT TESTIMONY OF
LARRY C. FOUST, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

Introduction

Q. Please state your name, business address, and position.

A. My name is Larry C. Foust. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I currently hold the position of Regulatory Specialist in the Regulated Pricing and Analysis department for the American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power Company, Inc. (AEP).

Background

Q. Please summarize your educational background and employment history.

A. I received my Bachelor of Science in Business Administration in 1977 from The Ohio State University, majoring in Accounting. I am a Certified Public Accountant (Inactive). In 1977 I began my career as a Budget Analyst in the Generation Department of the Columbus and Southern Ohio Electric Company. In 1979 I became an Accountant in the Special Studies section of the Accounting Department. After the Columbus and Southern Ohio Electric Company was acquired by AEP, I transferred to AEPSC in 1982 as a Rate Case Coordinator. In 1999 I became part of AEPSC's Customer Choice Implementation organization. In 2001 I became an Issues Manager in the Energy Delivery organization and in 2004 I accepted my current position.

Q. What are your principal areas of responsibility as a Regulatory Specialist in the Regulated Pricing and Analysis Department?

A. My responsibilities are to perform pricing and costing services for rate cases, regulatory filings and rulemakings, as well as provide pricing and costing services to Kentucky Power Company (KPCo) and other AEP electric utility operating companies in the areas of regulatory analysis, cost of service studies and rate design. I also assist KPCo and other AEP electric utility operating companies in the preparation of filings before this and other commissions under whose jurisdiction these companies provide electric service.

Q. For whom are you testifying in this proceeding?

A. I am testifying on behalf of Kentucky Power Company, which I will refer to throughout my testimony either as KPCo, or as "the Company".

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the Company's class cost of service study. A class cost of service study is an analysis of all of the Company's costs at a very detailed level for purposes of assigning these costs to the various customer classes. The class cost of service study is attached to my testimony as Exhibit LCF-1.

Class Cost of Service Study

Q. Briefly describe the nature and purpose of a cost of service study.

A. Cost studies are utilized to determine the revenue requirement for the services offered by the utility, and to determine the costs that different classes of customers impose on the utility system. A cost of service study is a basic analytical tool used in traditional utility rate design. When the process of preparing a cost of service study is completed and all of the costs are allocated to the various jurisdictions and customer classes, the result is a fully allocated cost study that establishes cost responsibility and makes it possible to determine rates based on costs that are just and reasonable.

Q. What is the source of the data to be used in a cost of service study?

A. Cost of service studies rely on historic or projected accounting records of the utility company. The Company follows the Uniform System of Accounts (USOA) as prescribed by FERC and adopted by this Commission. The USOA sets the guidelines for recording assets, liabilities, income and expenses into various accounts. The costs recorded in each FERC account are examined to verify compliance with these guidelines and are typically adjusted to reflect the applicable regulatory commission's policies and for known and measurable changes to the test year level of expenditures.

Q. After the costs recorded in FERC accounts are examined and adjusted where appropriate, how is this information used?

A. This accounting cost information is assigned to the different customer classes in a way that reflects the costs of providing utility service to the classes. A three-step process is followed to assign costs to the customer classes: functionalization of costs, classification of costs, and finally, allocation of costs.

Q. Please describe the functionalization process.

A. Once the relevant data is gathered, the costs are then separated by function. Typically, functions in an electric utility are:

1) Production and Purchased Power costs,

2) Transmission costs,

3) Distribution costs,

4) Customer Service costs, and

5) Administrative and General (A&G) costs.

The production function includes the costs associated with power generation and power purchases and their delivery to the bulk transmission system. The transmission function consists of costs associated with the high voltage system utilized for the bulk transmission of power to and from interconnected utilities to the load centers of the utility's system. The distribution function includes the radial distribution system that connects the transmission system and the ultimate customer. The customer service function encompasses the costs associated with providing meter reading, billing and collection, and customer information and services. The A&G function is comprised of costs that may not be directly assignable to other cost functions. These costs include such items as management costs and administrative buildings. A&G costs are generally allocated to the remaining functions based on labor.

Q. Please describe the classification process.

A. The second step is to separate the functionalized costs into these classifications: 1) demand costs (costs associated with the kW demand imposed by the customer), 2) energy costs (costs that vary with the number of kilowatt hours used by the customer), and 3) customer costs (costs that are directly related to the number of customers served). Typical cost classifications used in cost studies are:

Function	Classification
Production	Demand, Energy

Transmission	Demand
Distribution	Demand, Customer
Customer Service	Customer

Production plant costs, such as depreciation and return on investment, are considered to be demand-related costs because costs of this nature are incurred regardless of the amount of energy consumed or the number of customers. Some production costs such as fuel costs and certain production operation and maintenance (O&M) expenses are energy-related because they vary with the quantity of electricity produced. Transmission costs are classified as demand-related costs because they are fixed costs and do not vary with energy usage and do not directly change with the number of customers utilizing the transmission system. Generally, the distribution system costs are affected by either the instantaneous peak demand imposed on the distribution facilities or by the number of customers served. Demand related distribution costs typically vary with the size of the electrical load served, while customer related distribution costs vary based on the number of customers receiving the service. Customer service costs are primarily related to the number of customers. The classification process provides a basis on which to allocate different categories of costs (demand, energy or customer) to the Company's classes.

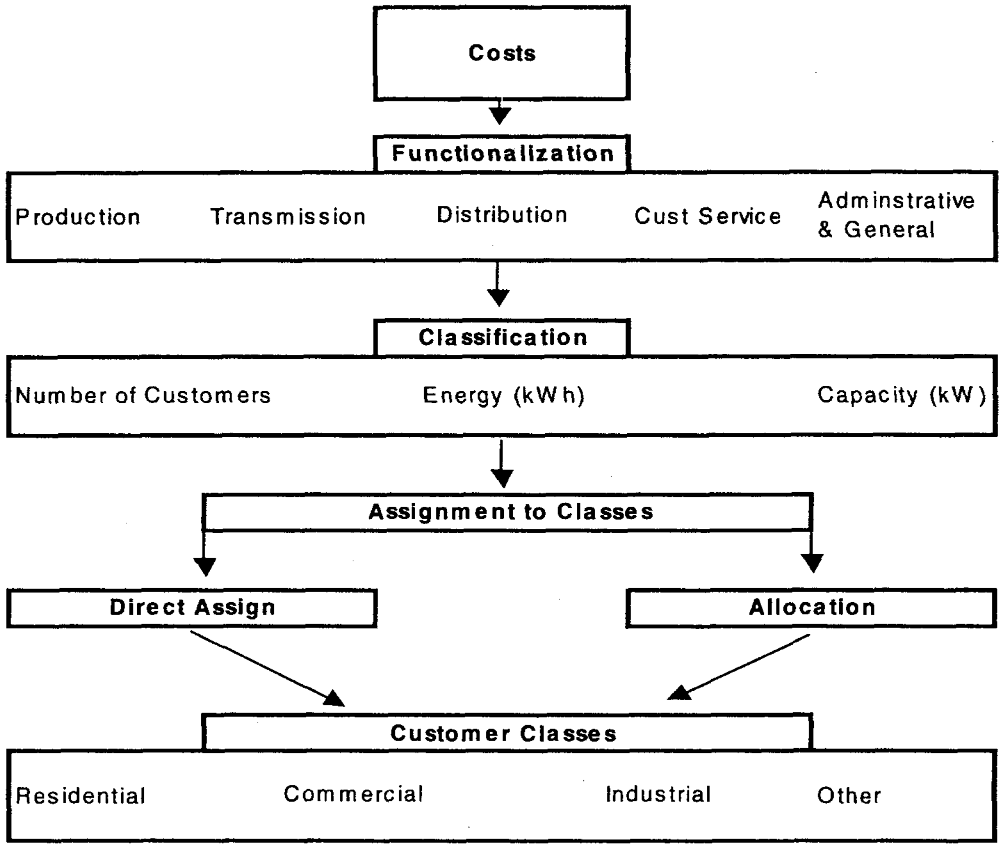
Q. Please describe the allocation process.

A. The third and final step is to allocate these costs among the classes of customers based on how the costs are incurred for each class. Customer classes are determined and grouped according to the nature of service provided, voltage level and the load usage characteristics. The three principal customer classes are residential, commercial, and industrial. The need to subdivide these classes depends on the individual customer base.

The allocation process involves dividing the functionalized and classified costs among the customer classes. The objective in this process is to determine a reasonable, appropriate, and understandable method to assign the costs. Some costs are directly assignable to a single class, or even a single customer. For instance, the costs associated with the poles and luminaries used for street lighting are directly assigned to the street lighting class. Most costs, however, are attributable to more than one type of customer. These are joint costs and must be allocated to customers by an allocation methodology that is based on the manner in which the costs are caused by the different customers. The following flowchart provides an overview of how the allocation of costs to customer classes is determined.

Figure 1:

Cost Allocation Example



In the example, costs are functionalized into production, transmission, distribution, etc. Some of these costs can be directly assigned to a customer class as mentioned previously. The remaining joint costs are incurred based on the number of customers, the energy used, or by the capacity demanded. In many instances, the classification process will lead to an allocation methodology. For example, the cost of billing customers varies with the number of customers as well as the complexity of preparing the customer's bill, so those costs associated with billing are allocated to the jurisdictions based on a weighted number of customers. A weighted number of customers allocation factor is developed by multiplying the number of customers in each class or jurisdiction by a factor representing the difference in cost associated with providing that service to different types of customers. Similarly, the cost of fuel varies by the number of kilowatt hours consumed and therefore is allocated based on the proportion of total energy used by a customer class.

When this process is completed and all of the costs are allocated to the jurisdictions and customer classes, the result is a fully allocated cost study that establishes cost responsibility and makes it possible to determine rates based on costs that are just and reasonable.

Q. What criteria must be established to ensure that the allocation of costs to the customers is appropriate?

A. Generally, the following criteria should be used to determine the appropriateness of an allocation methodology:

1) The method should reflect the planning and operating characteristics of the utility's system.
2) The method should recognize customer class characteristics such as energy usage, peak demand on the system, diversity characteristics, number of customers, etc.
3) The method should produce stable results on a year-to-year basis.
4) Customers who benefit from the use of the system should also bear appropriate cost responsibility for the system.

Q. Does the allocation method employed by the Company meet these objectives?

A. Yes, it does. The allocation methodology utilized in the Company's cost of service study was chosen while considering each of the criteria listed above. The results of the cost of service study can be relied upon to determine the appropriate revenue requirement for the KPCo customer classes.

Q. How does this cost of service study compare to the cost of service study filed by the Company in its previous rate case?

A. This cost of service study is substantially the same as the Company's cost of service study filed in the previous rate case. The functionalization and classification of costs are the same but a few small accounts were allocated on a slightly different basis using more current information.

Allocation Basis

Q. Please describe the allocation of Electric Plant in Service.

A. Electric Plant in Service is identified and functionalized into production, transmission, distribution and general plant. Production plant is classified as demand related and is allocated using the production demand allocation factor. The production demand allocation factor assigns costs based on the class contribution to the average of KPCo's 12 monthly peaks on the production facilities. Generator step-up transformers are included in transmission plant, but I have separately identified them and allocated them using the production demand allocation factor since they are more related to the production function. The remaining transmission plant is classified as demand related and is allocated using the transmission demand allocation factor. The transmission demand allocation factor assigns costs based on the class contribution to the average of KPCo's 12 monthly peaks on the transmission facilities. Distribution plant is classified as demand/customer related and allocated to the customer classes using factors based on demand levels or number of customers. Distribution plant accounts 360 through 368, as shown on Exhibit LCF-1, were classified solely as demand-related for class allocation purposes. Accounts 360, 361 and 362 were allocated to the distribution customer classes based on their contributions to the average of KPCo's 12 monthly peak demands on the primary distribution system.

Accounts 364 through 367 were split into primary and secondary voltage functions based upon information contained in the Company's records and the expertise of the Company's distribution engineers. The primary portions of accounts 364 through 367 were allocated using the average of 12 monthly peak demands on the distribution system. The secondary component of accounts 364 through 367 were allocated based on a combination of each class's 12-month maximum demand and the summation of individual customers' annual maximum demands in each class served from those facilities. This process reflects the fact that some secondary facilities serve only one customer, while others serve two or more customers.

Account 368 was allocated to the customer classes served from those facilities using the appropriate secondary voltage demand allocation factors described above.

Services, account 369, was classified as customer-related and was allocated using the average number of secondary customers served.

Meter plant was allocated using the average number of customers weighted by a factor which considers the cost differential of various metering installations. Account 371 was directly assigned to the outdoor lighting class and account 373 was directly assigned to the street lighting class. Classification of distribution plant into demand and customer components is accomplished through a study of the components of distribution plant. General and intangible plant and investment reflects a composite demand, energy and customer classification. General and intangible plant investment is allocated on the basis of payroll labor.

Q. Please describe the allocation of Accumulated Provision for Depreciation and Amortization.

A. Accumulated Provision for Depreciation and Amortization was functionalized and classified in a fashion similar to Electric Plant in Service. Production, transmission, distribution and general and intangible related amounts were allocated based upon the allocation of the related Electric Plant in Service.

Q. Please describe the allocation of other rate base components.

A. Working Capital was divided into cash, material and supplies and prepayments. Cash working capital is made up of system sales revenue, split between demand and energy and O&M expense net of system sales. Demand related system sales were allocated based upon the production demand allocation factor. Energy related system sales were allocated based upon the energy allocation factor and the O&M expense net of system sales was allocated based upon the allocation of total O&M expense. The energy allocation factor allocates costs based on the class energy used during the period compared to the total energy used by all classes. Materials and supplies were split between fuel stock, production and transmission and distribution. Fuel stock was allocated using the energy allocation factor. Production related material and supplies were allocated using the production demand allocation factor and the transmission and distribution related materials and supplies were allocated using the allocation of transmission and distribution electric plant in service. Prepayments were allocated using factors developed from gross plant relationships. Plant Held for Future Use is transmission related and allocated using transmission electric plant in service. Construction Work in Progress was functionalized and allocated using appropriate related factors. Customer Deposits were assigned based on an analysis of accounting records. Accumulated Deferred Federal Income Tax Credits were allocated on electric plant in service and customer advances were allocated based on the number of customers.

Q. How were revenues developed for each class?

A. Sales revenue was directly assigned to each class.

Forfeited discounts were directly assigned based on an analysis of accounting records. Miscellaneous service revenue was allocated on distribution electric plant in service

Rent from electric property and other electric revenue was functionalized and allocated to classes based on related functional allocators.

Q. Please describe the allocation of production operation and maintenance expense.

A. Production related O&M was classified as either demand or energy related. The demand component was allocated using the production demand allocation factor and the energy component was allocated using the energy allocation factor. Demand-related system sales revenue was allocated based on the production demand allocation factor. Energy-related system sales revenue was allocated on the energy allocation factor.

Q. Please describe the allocation of transmission O&M.

A. Transmission related O&M was classified as demand related and allocated using the transmission demand allocation factor.

Q. Please describe the allocation of distribution O&M between the various customer classes.

A. Distribution O&M expenses were functionalized and classified according to the associated distribution plant accounts and allocated accordingly. Accounts 581, Load Dispatching and 582, Station Expenses were allocated using the distribution demand allocation factor. Account 583 Overhead Line Expense was allocated based upon the same allocation used for plant account 365 Overhead Lines. Account 584 Underground Line Expense was allocated based upon the same allocation used for plant accounts 366 Underground Conduit and 367 Underground Lines. Account 585, Street Lighting Operation Expense, was classified as customer-related and directly assigned to the street lighting class. Meter Operation Expense, account 586, was classified customer-related and allocated in the same manner as meter plant. Account 587, Customer Installation Expense was classified customer-related and allocated based on primary customers.

Accounts 588 and 589 were allocated on total distribution plant and classified accordingly. Account 580 was classified demand- and customer-related and allocated using the allocated subtotal of accounts 581 through 589.

Account 591 and 592 were classified demand-related and allocated on the distribution demand allocation factor. Accounts 593, 594, and 595 were functionalized and classified according to the associated distribution plant accounts and allocated accordingly. Distribution maintenance account 596 was directly assigned to the street lighting class. Account 597 was classified customer-related and allocated in the same manner as meter plant. Account 598 was classified customer-related and directly assigned to the outdoor lighting class. Account 590 was classified and allocated based on the sum of the allocated O&M expense accounts 591 through 598.

Q. Can you explain how customer accounting (accounts 901-905), customer services (accounts 907-910) and sales expense (accounts 911-916) were allocated?

A. Account 902, Meter Reading Expense, was allocated to those classes with meter installations based upon an average number of customers weighted to reflect differences in meter reading requirements. Customer Records Expense, account 903, was divided into two categories of cost; call center and other. Call center costs were first split into residential and other based on the number of calls received and then other call center expenses were allocated based on the number of customers. The other category of expenses was allocated based on the number of customers. Account 904, Uncollectibles, was allocated based on the number of customers. Accounts 901 and 905 were allocated based on the sum of the allocated accounts 902, 903 and 904. All customer accounting expenses were classified as customer-related.

Accounts 907 through 916 were allocated based on the number of customers.

Q. Please describe the allocation of administrative and general (A&G) expense.

A. A&G expense, excluding regulatory expense, was functionalized and classified using O&M labor expense. The functionalized/classified cost was then allocated using the appropriate functional classification allocator. A&G regulatory expense was allocated based on gross utility plant.

Q. Please describe the allocation of depreciation and amortization expense.

A. The functionalized components of depreciation and amortization expense were allocated using the corresponding plant items.

Q. How were taxes assigned to the retail classes?

A. Individual other tax items were allocated and classified using the appropriate demand or plant allocator.

Interest expense was allocated on rate base and individual Schedule M items were allocated using the appropriate allocators. State and current Federal income taxes were computed by class. Feedback of prior Investment Tax Credit Normalized was allocated based on gross utility plant and individual Deferred Federal Income Tax items were allocated using the appropriate allocation factors.

Q. Please describe the allocation of the Allowance for Funds Used During Construction (AFUDC) offset.

A. The functionalized components of the AFUDC offset were allocated using the corresponding plant allocator.

Q. What is the resulting earned rate of return for each class shown in the class cost of service study?

A. The resulting earned rates of return are as follows:

CLASS	ROR
Residential	-0.09 %
Small General Service	7.69 %
Medium General Service	9.86 %
Large General Service	6.26 %
Quantity Power	6.94 %
Commercial and Industrial Power - Time of Day	5.79 %
Municipal Waterworks	7.63 %
Outdoor Lighting	2.12 %
Street Lighting	9.77 %
Total KPCo Jurisdiction	3.31 %

Q. How are these rates of return used in this proceeding?

A. Witness Roush uses the earned rates of return for each class as a basis for the allocation of the revenue increase required for each class.

Q. Does this conclude your direct testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

STATE OF OHIO

CASE NO. 2005-00341

COUNTY OF FRANKLIN

AFFIDAVIT

LARRY C. FOUST, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Larry C Foust

LARRY C. FOUST

Subscribed and sworn to before me by LARRY C. FOUST this 20th day of September, 2005.

W. J. Resnik

Notary Public

My Commission Expires ~~NOTARY PUBLIC~~ Attorney At Law - STATE OF OHIO LIFETIME COMMISSION

KENTUCKY POWER COMPANY
12 CP CLASS COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2005
Summary

	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
RATE BASE										
GROSS UTILITY PLANT	1,336,938,136	690,649,209	22,354,354	129,335,535	147,576,744	115,178,044	200,475,882	1,198,858	26,786,524	3,382,985
TOTAL DEPRECIATION RESERVE	432,998,450	219,971,362	6,929,358	41,558,258	48,039,977	38,798,360	68,438,655	384,995	7,879,985	997,500
NET UTILITY PLANT	903,939,686	470,677,847	15,424,996	87,777,277	99,536,767	76,379,684	132,037,227	813,863	18,906,539	2,385,485
TOTAL CWIP	19,159,718	10,217,345	347,483	1,879,599	2,093,035	1,513,363	2,580,549	17,457	453,798	57,088
PLANT HELD FOR FUTURE USE TRANS	83,282	35,405	759	7,407	9,691	10,371	19,540	68	34	8
TOTAL WORKING CAPITAL	73,842,577	30,408,904	992,365	6,706,412	8,256,874	8,545,932	17,994,249	70,729	769,427	97,686
TOTAL RATE BASE OFFSETS	(138,581,504)	(73,691,885)	(2,424,056)	(13,801,776)	(14,714,538)	(11,440,890)	(19,410,905)	(114,672)	(2,657,788)	(324,994)
TOTAL RATE BASE	858,443,759	437,647,616	14,341,548	82,568,918	95,181,830	75,008,460	133,220,660	787,445	17,472,010	2,215,273
OPERATING REVENUES										
SALES OF ELECTRICITY	337,343,688	130,089,965	6,396,711	40,049,839	41,639,263	39,023,377	74,184,655	367,037	4,776,969	815,872
OTHER OPERATING REVENUE	8,713,065	5,095,871	243,958	1,095,981	910,611	411,105	662,398	9,207	250,747	33,187
TOTAL OPERATING REVENUE	346,056,753	135,185,836	6,640,669	41,145,820	42,549,874	39,434,482	74,847,053	376,244	5,027,716	849,059
OPERATING EXPENSES										
ADJUSTED OPERATING AND MAINTENANCE EXP	266,996,120	118,449,612	4,192,553	24,482,993	29,226,044	28,378,307	58,026,194	247,981	3,601,207	391,229
ADJUSTED DEPRECIATION EXPENSE	47,698,792	25,182,176	856,272	4,645,752	5,204,493	3,877,457	6,667,080	43,037	1,088,021	134,504
ADJUSTED TAXES OTHER THAN INCOME TAX	9,198,011	4,701,552	163,522	895,283	1,007,299	799,621	1,408,259	8,249	191,239	22,986
TOTAL STATE INCOME TAXES	(1,348,227)	(2,335,824)	61,116	527,629	181,974	162,018	69,434	2,909	(34,139)	16,657
FEDERAL INCOME TAXES	(3,660,566)	(9,849,487)	280,912	2,564,160	1,107,446	1,135,386	1,192,139	15,073	(175,219)	69,024
TOTAL EXPENSES	318,884,131	136,148,029	5,554,374	33,115,817	36,727,256	34,352,789	67,363,107	317,249	4,671,108	634,401
NET OPERATING INCOME	27,172,622	(962,193)	1,086,295	8,030,003	5,822,617	5,081,693	7,483,946	58,995	356,607	214,658
AFUDC OFFSET	1,234,029	587,830	16,218	115,050	139,787	126,615	232,778	1,065	13,009	1,675
ADJUSTED NET OPERATING INCOME	28,406,651	(374,363)	1,102,513	8,145,054	5,962,405	5,208,308	7,716,724	60,060	369,617	216,333
RATE OF RETURN %	3.31%	-0.09%	7.69%	9.86%	6.26%	6.94%	5.79%	7.63%	2.12%	9.77%
RATE OF RETURN INDEX	100	(3)	232	298	189	210	175	230	64	295

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED JUNE 30, 2005

	METHOD	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
ELECTRIC PLANT IN SERVICE											
PRODUCTION PLANT DEMAND	PROD_DEMAND	452,727,608	197,278,411	4,248,784	40,659,852	52,714,404	53,991,470	103,089,256	376,289	298,715	70,627
TRANSMISSION PLANT OTHER DEMAND TOTAL	TRANS_TOTAL	380,818,658	161,876,867	3,471,221	33,867,796	44,311,741	47,430,651	89,360,417	310,453	153,274	36,239
TRANSMISSION PLANT GSU TOTAL	PROD_DEMAND	1,577,091	687,226	14,801	141,639	183,632	188,081	359,115	1,311	1,041	246
TRANSMISSION PLANT		382,395,749	162,564,093	3,486,021	34,009,435	44,495,373	47,618,732	89,719,532	311,764	154,315	36,485
DISTRIBUTION PLANT											
360 LAND AND LAND RIGHTS	DIST_CPD	5,128,881	3,469,035	77,348	661,127	697,141	203,901	0	6,406	11,548	2,375
361 STRUCTURES AND IMPROVEMENTS	DIST_CPD	4,186,156	2,831,401	63,131	539,607	569,001	166,423	0	5,228	9,425	1,938
362 STATION EQUIPMENT	DIST_CPD	41,861,612	28,314,049	631,314	5,396,081	5,690,021	1,664,229	0	52,284	94,252	19,382
364 POLES	DIST_POLES	126,864,495	91,072,686	2,349,912	15,212,031	14,484,250	2,834,481	0	154,454	641,668	115,013
365 OVERHEAD LINES	DIST_OHLINES	102,420,173	72,564,010	1,817,447	12,489,204	12,197,006	2,691,437	0	125,422	453,064	82,584
366 UNDERGROUND CONDUIT	DIST_UGLINES	3,053,885	2,174,074	55,055	370,136	358,221	75,880	0	3,732	14,214	2,574
367 UNDERGROUND LINES	DIST_UGLINES	5,923,247	4,216,785	106,784	717,907	694,797	147,176	0	7,238	27,568	4,992
368 TRANSFORMERS	DIST_TRANSF	84,645,406	65,272,101	1,941,723	9,172,683	7,301,425	0	0	99,632	732,928	124,914
369 SERVICES	DIST_SERV	31,586,289	20,547,459	2,542,225	1,628,486	99,567	0	0	2,987	6,757,741	7,823
370 METERS	DIST_METERS	20,937,281	9,482,984	3,791,663	3,107,766	2,533,860	1,602,733	413,817	4,457	0	0
371 INSTALLATIONS ON CUST PREMISES	DIST_OL	16,201,414	0	0	0	0	0	0	0	16,201,414	0
372 LEASED PROP ON CUST PREMISES	DIST_OL	0	0	0	0	0	0	0	0	0	0
373 STREET LIGHTING	DIST_SL	2,788,123	0	0	0	0	0	0	0	0	2,788,123
DISTRIBUTION PLANT TOTAL		445,596,962	299,944,584	13,376,603	49,295,028	44,625,288	9,386,261	413,817	461,841	24,943,822	3,149,718
PTD PLANT	FORMULA	1,280,720,319	659,787,088	21,111,408	123,964,115	141,835,065	110,996,463	193,222,605	1,149,893	25,396,852	3,256,830
GENERAL PLANT TOTAL	LABOR_M	49,011,035	26,380,860	1,132,858	4,574,389	4,902,929	3,780,163	6,711,963	41,097	1,365,129	121,647
HR-J 765 LINE - AFUDC	BULK_TRANS	1,722,182	750,450	16,162	154,670	200,526	205,384	392,153	1,431	1,136	269
ELECTRIC PLANT IN SERVICE		1,331,453,536	686,918,398	22,260,428	128,693,174	146,938,521	114,982,010	200,326,721	1,192,421	26,763,117	3,378,746
ELECTRIC PLANT IN SERVICE - ADJUSTMENT		5,484,600	3,730,811	93,926	642,361	638,223	196,034	149,161	6,437	23,407	4,239
GROSS UTILITY PLANT	FORMULA	1,336,938,136	690,649,209	22,354,354	129,335,535	147,576,744	115,178,044	200,475,882	1,198,858	26,786,524	3,382,985
DEPRECIATION RESERVE											
PRODUCTION	RB_GUP_EPIS_P	172,837,498	75,314,839	1,622,055	15,522,607	20,124,741	20,612,285	39,356,312	143,656	114,040	26,963
TRANSMISSION	RB_GUP_EPIS_T	114,198,348	48,548,005	1,041,062	10,156,549	13,288,061	14,220,818	26,793,766	93,105	46,084	10,896
DISTRIBUTION	RB_GUP_EPIS_D	130,586,204	87,901,463	3,920,134	14,446,352	13,077,843	2,750,728	121,273	135,347	7,310,012	923,053
GENERAL	RB_GUP_EPIS_G	14,698,381	7,911,605	339,743	1,371,857	1,470,386	1,133,669	2,012,914	12,325	409,401	36,482
HR-J POST IN-SERVICE	BULK_TRANS	678,019	295,450	6,363	60,893	78,947	80,859	154,390	564	447	106
TOTAL DEPRECIATION RESERVE		432,998,450	219,971,362	6,929,358	41,558,258	48,039,977	38,798,360	68,438,655	384,995	7,879,985	997,500
NET UTILITY PLANT	FORMULA	903,939,686	470,677,847	15,424,996	87,777,277	99,536,767	76,379,684	132,037,227	813,863	18,906,539	2,385,485

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED JUNE 30, 2005

	METHOD	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
PLANT HELD FOR FUTURE USE TRANS	RB_GUP_EPIS_T	83,282	35,405	759	7,407	9,691	10,371	19,540	68	34	8
WORKING CAPITAL											
WORKING CAPITAL CASH											
WORKING CAPITAL CASH EXCL SYS SALES	EXP_OM	29,436,141	12,757,005	449,790	2,666,893	3,208,791	3,222,951	6,662,579	27,277	397,227	43,628
SYSTEM SALES ADD BACK DEMAND	PROD_DEMAND	2,511,767	1,094,516	23,573	225,583	292,463	299,549	571,947	2,088	1,657	392
SYSTEM SALES ADD BACK ENERGY	PROD_ENERGY	13,172,434	4,477,089	132,277	1,174,866	1,519,443	1,769,570	3,992,111	13,817	77,599	15,661
TOTAL WORKING CAPITAL CASH		45,120,342	18,328,610	605,640	4,067,342	5,020,698	5,292,070	11,226,637	43,182	476,483	59,681
WORKING CAPITAL CASH - ADJUSTMENT		3,938,374	2,049,197	74,279	393,481	444,464	324,337	590,696	3,721	52,924	5,275
WORKING CAPITAL MATERIALS & SUPPLIES											
FUEL	PROD_ENERGY	10,524,611	3,577,139	105,688	938,704	1,214,016	1,413,865	3,189,647	11,040	62,000	12,513
PRODUCTION	PROD_DEMAND	5,089,261	2,217,672	47,762	457,069	592,580	606,936	1,158,860	4,230	3,358	794
TRANSMISSION AND DISTRIBUTION	TDPLANT	888,306	495,973	18,071	89,353	95,629	61,250	96,918	830	26,872	3,411
TOTAL MATERIALS & SUPPLIES		16,502,178	6,290,783	171,521	1,485,125	1,902,225	2,082,051	4,445,426	16,099	92,230	16,718
WORKING CAPITAL MATERIALS & SUPPLIES - ADJUSTMENT		3,542,537	1,204,049	35,574	315,963	408,632	475,900	1,073,621	3,716	20,869	4,212
WORKING CAPITAL PREPAYMENTS	RB_GUP_EPIS	655,315	338,088	10,956	63,340	72,320	56,592	98,597	587	13,172	1,663
WORKING CAPITAL PREPAYMENTS - ADJUSTMENT		4,083,831	2,198,178	94,395	381,160	408,535	314,981	559,272	3,424	113,749	10,136
TOTAL WORKING CAPITAL	FORMULA	73,842,577	30,408,904	992,365	6,706,412	8,256,874	8,545,932	17,994,249	70,729	769,427	97,686
CONSTRUCTION WORK IN PROGRESS											
PRODUCTION	RB_GUP_EPIS_P	9,503,956	4,141,398	89,193	853,554	1,106,615	1,133,424	2,164,118	7,899	6,271	1,483
TRANSMISSION	RB_GUP_EPIS_T	1,204,283	511,965	10,979	107,106	140,130	149,966	282,555	982	486	115
DISTRIBUTION	RB_GUP_EPIS_D	7,524,931	5,065,255	225,895	832,460	753,601	158,509	6,988	7,799	421,234	53,190
GENERAL	RB_GUP_EPIS_G	926,548	498,727	21,417	86,478	92,689	71,464	126,889	777	25,808	2,300
TOTAL CWIP		19,159,718	10,217,345	347,483	1,879,599	2,093,035	1,513,363	2,580,549	17,457	453,798	57,088
RATE BASE OFFSETS											
DEFERRED FIT	RB_GUP	(127,983,435)	(66,028,723)	(2,139,741)	(12,370,386)	(14,124,185)	(11,052,427)	(19,256,024)	(114,619)	(2,572,554)	(324,775)
CUSTOMER ADVANCES	CUST_TOTAL	(56,784)	(36,878)	(4,563)	(2,950)	(220)	(22)	(4)	(5)	(12,129)	(14)
CUSTOMER DEPOSITS	CUST_DEP	(10,541,285)	(7,631,458)	(283,160)	(1,425,679)	(584,240)	(384,548)	(148,685)	0	(83,516)	0
TOTAL RATE BASE OFFSETS		(138,581,504)	(73,691,885)	(2,424,056)	(13,801,776)	(14,714,538)	(11,440,890)	(19,410,905)	(114,672)	(2,657,788)	(324,994)
TOTAL RATE BASE	FORMULA	858,443,759	437,647,616	14,341,548	82,568,918	95,181,830	75,008,460	133,220,660	787,445	17,472,010	2,215,273

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED JUNE 30, 2005

	METHOD	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
OPERATING REVENUES											
TOTAL REVENUE	REVSALES	337,148,564	130,195,491	6,280,382	39,974,995	41,493,781	39,120,307	74,184,655	365,580	4,715,283	818,090
TOTAL REVENUE YEAR END CUSTOMERS	REVYEC	195,124	(105,526)	116,329	74,844	145,482	(96,930)	0	1,457	61,686	(2,218)
SALES OF ELECTRICITY		337,343,688	130,089,965	6,396,711	40,049,839	41,639,263	39,023,377	74,184,655	367,037	4,776,969	815,872
OTHER OPERATING REVENUES											
FORFEITED DISCOUNTS	FORT	1,476,289	866,530	74,711	290,715	136,208	94,941	0	0	13,184	0
MISCELLANEOUS SERVICE REVENUE	RB_GUP_EPIS_D	250,274	168,467	7,513	27,687	25,064	5,272	232	259	14,010	1,769
RENT FROM ELECTRIC PROP POLES	DIST_POLES	2,602,948	1,868,588	48,214	312,114	297,181	58,157	0	3,169	13,165	2,360
RENT FROM ELECTRIC PROP OTHER DIST	RB_GUP_EPIS_D	435,543	293,177	13,075	48,183	43,618	9,174	404	451	24,381	3,079
OTHER ELECTRIC REVENUE DIST	RB_GUP_EPIS_D	2,189,343	1,473,712	65,723	242,200	219,257	46,117	2,033	2,269	122,556	15,475
OTHER ELECTRIC REVENUE WHEELING	TRANS_TOTAL	172,219	73,206	1,570	15,316	20,039	21,450	40,412	140	69	16
OTHER ELECTRIC REVENUE PRODUCTION	PROD_ENERGY	5,856,518	1,990,532	58,811	522,350	675,550	786,758	1,774,909	6,143	34,501	6,963
TOTAL OTHER OPERATING REVENUES		12,983,134	6,734,212	269,617	1,458,565	1,416,918	1,021,869	1,817,991	12,432	221,866	29,662
OTHER OPERATING REVENUE - ADJUSTMENT		(4,270,069)	(1,638,341)	(25,659)	(362,584)	(506,308)	(610,764)	(1,155,593)	(3,225)	28,880	3,525
TOTAL OPERATING REVENUE		346,056,753	135,185,836	6,640,669	41,145,820	42,549,874	39,434,482	74,847,053	376,244	5,027,716	849,059

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED JUNE 30, 2005

OPERATION AND MAINTENANCE EXPENSE	METHOD	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
O&M EXPENSE PRODUCTION											
GENERATION EXPENSE DEMAND	PROD_DEMAND	17,732,601	7,727,073	166,418	1,592,572	2,064,737	2,114,758	4,037,838	14,739	11,700	2,766
GENERATION EXPENSE ENERGY	PROD_ENERGY	10,290,416	3,497,540	103,336	917,816	1,187,001	1,382,403	3,118,671	10,794	60,621	12,234
GENERATION EXPENSE FUEL	PROD_ENERGY	110,407,982	37,525,820	1,108,716	9,847,431	12,735,582	14,832,086	33,460,859	115,811	650,412	131,265
SYSTEM SALES	PROD_DEMAND	(20,094,132)	(8,756,123)	(188,581)	(1,804,662)	(2,339,708)	(2,396,390)	(4,575,575)	(16,701)	(13,258)	(3,135)
SYSTEM SALES	PROD_ENERGY	(105,379,475)	(35,816,715)	(1,058,220)	(9,398,932)	(12,155,543)	(14,156,562)	(31,936,892)	(110,536)	(620,789)	(125,287)
PURCHASED POWER DEMAND	PROD_DEMAND	70,249,303	30,611,499	659,280	6,309,119	8,179,643	8,377,804	15,996,260	58,388	46,351	10,959
PURCHASED POWER ENERGY	PROD_ENERGY	96,186,225	32,692,083	965,901	8,578,974	11,095,099	12,921,551	29,150,734	100,893	566,632	114,357
SYSTEM CONTROL	PROD_DEMAND	2,769,001	1,206,607	25,987	248,685	322,415	330,226	630,521	2,301	1,827	432
TOTAL PRODUCTION EXPENSES		182,161,921	68,687,785	1,782,838	16,291,003	21,089,228	23,405,876	49,882,416	175,689	703,495	143,592
O&M EXPENSE TOTAL TRANSMISSION	TRANS_TOTAL	514,789	218,824	4,692	45,782	59,900	64,117	120,797	420	207	49
DISTRIBUTION OPERATION EXPENSE											
580 SUPERVISION & ENGINEERING	TOTOXEXP	890,661	580,069	39,751	100,698	90,030	24,113	2,236	835	46,359	6,570
581 LOAD DISPATCHING	DIST_CPD	339,546	229,660	5,121	43,768	46,153	13,499	0	424	764	157
582 STATION EXPENSES	DIST_CPD	206,824	139,890	3,119	26,660	28,112	8,222	0	258	466	96
583 OVERHEAD LINES	DIST_OHLINES	70,983	50,291	1,260	8,656	8,453	1,865	0	87	314	57
584 UNDERGROUND LINES	DIST_UGLINES	30,930	22,019	558	3,749	3,628	769	0	38	144	26
585 STREET LIGHTING	DIST_SL	11,424	0	0	0	0	0	0	0	0	11,424
586 METERS	DIST_METERS	507,306	229,771	91,871	75,301	61,395	38,834	10,027	108	0	0
587 CUSTOMER INSTALLS	DIST_PCUST	266,495	173,191	21,428	13,826	963	37	0	25	56,960	66
588 MISCELLANEOUS DISTRIBUTION	RB_GUP_EPIS_D	2,692,528	1,812,421	80,828	297,866	269,649	56,717	2,500	2,791	150,724	19,032
589 RENTS	RB_GUP_EPIS_D	1,371,216	923,006	41,163	151,693	137,323	28,884	1,273	1,421	76,759	9,692
TOTAL DISTRIBUTION OPER EXP	FORMULA	6,387,913	4,160,318	285,099	722,217	645,707	172,939	16,037	5,987	332,488	47,121
DISTRIBUTION MAINTENANCE EXPENSE											
590 SUPERVISION & ENGINEERING	TOTMXEXP	12,353	8,436	227	1,429	1,373	285	1	14	497	91
591 STRUCTURES	DIST_CPD	7,628	5,159	115	983	1,037	303	0	10	17	4
592 STATION EQUIPMENT	DIST_CPD	670,333	453,395	10,109	86,408	91,115	26,649	0	837	1,509	310
593 OVERHEAD LINES	TOTOHLINES	11,147,628	7,955,879	202,613	1,346,811	1,297,220	268,665	0	13,607	53,225	9,607
594 UNDERGROUND LINES	TOTUGLINES	103,865	73,942	1,872	12,589	12,183	2,581	0	127	483	88
595 LINE TRANSFORMER	DIST_TRANSF	604,245	465,948	13,861	65,480	52,122	0	0	711	5,232	892
596 STREET LIGHTING	DIST_SL	86,472	0	0	0	0	0	0	0	0	86,472
597 METERS	DIST_METERS	70,662	32,004	12,797	10,489	8,552	5,409	1,397	15	0	0
598 MISC DISTRIBUTION PLANT	DIST_OL	468,604	0	0	0	0	0	0	0	468,604	0
TOTAL DISTRIBUTION MAINT EXP	FORMULA	13,171,790	8,994,763	241,595	1,524,188	1,463,601	303,893	1,398	15,322	529,568	97,464
CUSTOMER ACCOUNTS											
901 SUPERVISION	TOTOX234	481,953	376,118	36,613	27,759	2,557	294	48	43	38,446	74
902 METER READ	CUST_902	2,067,779	1,641,348	203,075	197,218	22,525	2,897	477	239	0	0
903 CUSTOMER RECORDS	CUST_903	5,721,488	4,434,767	388,750	251,308	18,770	1,849	304	457	624,086	1,196
904 UNCOLLECTIBLES	CUST_TOTAL	(20,325)	(13,200)	(1,633)	(1,056)	(79)	(8)	(1)	(2)	(4,341)	(5)
905 MISCELLANEOUS	TOTOX234	15,976	12,468	1,214	920	85	10	2	1	1,274	2
TOTAL CUSTOMER ACCOUNTS		8,266,871	6,451,500	628,019	476,150	43,859	5,042	830	738	659,466	1,267
TOTAL CUSTOMER SERVICES	CUST_TOTAL	1,368,356	888,672	109,951	71,078	5,309	523	86	129	292,270	338

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED JUNE 30, 2005

	METHOD	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
ADMINISTRATIVE & GENERAL EXPENSE											
A&G PRODUCTION DEMAND	PROD_DEMAND	9,052,131	3,944,513	84,953	812,976	1,054,006	1,079,541	2,061,234	7,524	5,973	1,412
A&G PRODUCTION ENERGY	PROD_ENERGY	2,655,730	902,638	26,669	236,868	306,339	356,768	804,860	2,786	15,645	3,157
A&G TRANSMISSION	EXP_OM_TRAN	1,702,768	723,806	15,521	151,434	198,133	212,078	399,560	1,388	685	162
A&G DISTRIBUTION	EXP_OM_DIST	7,289,823	4,902,846	196,297	837,226	786,131	177,714	6,498	7,942	321,285	53,886
A&G CUSTOMER ACCOUNTS	EXP_OM_CUSTACCT	2,244,006	1,751,232	170,473	129,249	11,905	1,369	225	200	179,009	344
A&G CUSTOMER SERVICE	EXP_OM_CUSTSERV	642,816	417,474	51,652	33,390	2,494	246	40	61	137,301	159
A&G REGULATORY RECLASSIFIED	FORMULA	30,211	11,666	563	3,582	3,718	3,505	6,647	33	423	73
TOTAL A & G EXPENSES		23,617,485	12,654,175	546,127	2,204,725	2,362,726	1,831,220	3,279,066	19,933	660,320	59,194
TOTAL O&M EXPENSES		235,489,125	102,056,037	3,598,319	21,335,143	25,670,329	25,783,610	53,300,629	218,217	3,177,815	349,026
OPERATION & MAINTENANCE EXPENSE - ADJUSTMENT		31,506,995	16,393,575	594,233	3,147,850	3,555,715	2,594,697	4,725,565	29,764	423,392	42,204
ADJUSTED OPERATING AND MAINTENANCE EXP	FORMULA	266,996,120	118,449,612	4,192,553	24,482,993	29,226,044	28,378,307	58,026,194	247,981	3,601,207	391,229
DEPRECIATION EXPENSE											
PRODUCTION	RB_GUP_EPIS_P	17,327,512	7,550,554	162,616	1,556,191	2,017,570	2,066,448	3,945,596	14,402	11,433	2,703
TRANSMISSION	RB_GUP_EPIS_T	6,690,652	2,844,330	60,994	595,052	778,521	833,169	1,569,793	5,455	2,700	638
DISTRIBUTION	RB_GUP_EPIS_D	15,738,192	10,593,846	472,453	1,741,068	1,576,136	331,517	14,616	16,312	880,999	111,246
GENERAL PLANT	RB_GUP_EPIS_G	4,287,524	2,307,818	99,103	400,171	428,912	330,692	587,168	3,595	119,423	10,642
TOTAL DEPRECIATION EXPENSE		44,043,880	23,296,548	795,166	4,292,482	4,801,138	3,561,825	6,117,173	39,764	1,014,555	125,229
DEPRECIATION EXPENSE - ADJUSTMENT		3,654,912	1,885,628	61,106	353,270	403,354	315,632	549,908	3,273	73,466	9,275
ADJUSTED DEPRECIATION EXPENSE	FORMULA	47,698,792	25,182,176	856,272	4,645,752	5,204,493	3,877,457	6,667,080	43,037	1,088,021	134,504
TAXES OTHER THAN INCOME											
FEDERAL INSURANCE TAX	LABOR_M	2,152,118	1,158,407	49,745	200,865	215,292	165,990	294,728	1,805	59,944	5,342
FEDERAL UNEMPLOYMENT TAX	LABOR_M	25,730	13,850	595	2,401	2,574	1,985	3,524	22	717	64
KENTUCKY SALES & USE TAX	TDPLANT	212	118	4	21	23	15	23	0	6	1
KENTUCKY R/E PRS & FRANCHISE TAX	RB_GUP	6,984,383	3,603,356	116,771	675,084	770,793	603,159	1,050,850	6,255	140,391	17,724
LOUISIANA REAL & PERSONAL PROPERTY TAX	RB_GUP	584	301	10	56	64	50	88	1	12	1
KENTUCKY UNEMPLOYMENT TAX	LABOR_M	17,259	9,290	399	1,611	1,727	1,331	2,364	14	481	43
KENTUCKY PSC MAINTENANCE TAX RECLASSIFIED	FORMULA	504,415	194,788	9,396	59,807	62,080	58,529	110,989	547	7,055	1,224
KENTUCKY LICENSE TAX	RB_GUP	99	51	2	10	11	9	15	0	2	0
OHIO FRANCHISE TAX	PROD_DEMAND	89,805	39,133	843	8,065	10,457	10,710	20,449	75	59	14
WEST VIRGINIA REAL & PERSONAL PROPERTY TAX	RB_GUP	3,271	1,688	55	316	361	282	492	3	66	8
WEST VIRGINIA UNEMPLOYMENT TAX	LABOR_M	2,973	1,600	69	277	297	229	407	2	83	7
WEST VIRGINIA FRANCHISE TAX	LABOR_M	23,533	12,667	544	2,196	2,354	1,815	3,223	20	655	58
WEST VIRGINIA LICENSE TAX	LABOR_M	275	148	6	26	28	21	38	0	8	1
WYOMING LICENSE TAX	PROD_DEMAND	49	21	0	4	6	6	11	0	0	0
FRINGE BENEFIT LOADING FICA	LABOR_M	(805,537)	(433,591)	(18,619)	(75,184)	(80,584)	(62,130)	(110,317)	(675)	(22,437)	(1,999)
FRINGE BENEFIT LOADING FUT	LABOR_M	(12,251)	(6,594)	(283)	(1,143)	(1,226)	(945)	(1,678)	(10)	(341)	(30)
FRINGE BENEFIT LOADING SUT	LABOR_M	(5,307)	(2,857)	(123)	(495)	(531)	(409)	(727)	(4)	(148)	(13)
R/E PRS FRANCHISE - CARRS TAX	RB_GUP	(44,296)	(22,853)	(741)	(4,281)	(4,888)	(3,825)	(6,665)	(40)	(890)	(112)
TOTAL TAXES OTHER THAN INCOME		8,937,315	4,569,523	158,673	869,638	978,837	776,822	1,367,815	8,014	185,662	22,332
TAXES OTHER THAN INCOME TAXES - ADJUSTMENT		260,696	132,029	4,850	25,645	28,462	22,799	40,444	235	5,577	654
ADJUSTED TAXES OTHER THAN INCOME TAX	FORMULA	9,198,011	4,701,552	163,522	895,283	1,007,299	799,621	1,408,259	8,249	191,239	22,986
TOTAL OPERATING REVENUE		346,056,753	135,185,836	6,640,669	41,145,820	42,549,874	39,434,482	74,847,053	376,244	5,027,716	849,059
TOTAL OPERATING EXPENSE BEFORE TAXES		323,892,923	148,333,341	5,212,347	30,024,028	35,437,836	33,055,384	66,101,533	299,268	4,880,466	548,720
GROSS OPERATING INCOME	FORMULA	22,163,830	(13,147,505)	1,428,322	11,121,793	7,112,038	6,379,098	8,745,520	76,977	147,250	300,339
INTEREST CHARGE TAX	RATEBASE	(28,829,564)	(14,697,748)	(481,640)	(2,772,955)	(3,196,541)	(2,519,048)	(4,474,019)	(26,445)	(586,772)	(74,397)
INTEREST SYNCRONIZATION TAX	RATEBASE	1,221,632	622,806	20,409	117,502	135,451	106,743	189,583	1,121	24,864	3,153
NET OPER INCOME BEFORE INCOME TAX	FORMULA	(5,444,102)	(27,222,446)	967,091	8,466,339	4,050,948	3,966,792	4,461,084	51,652	(414,658)	229,095

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED JUNE 30, 2005

INCOME TAXES	METHOD	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
SCHEDULE M INCOME ADJUSTMENTS											
BOOK VS TAX DEPRECIATION NORMALIZED	RB_GUP	(6,012,634)	(3,102,015)	(100,525)	(581,158)	(663,551)	(519,241)	(904,644)	(5,385)	(120,858)	(15,258)
BOOK VS TAX DEPRECIATION FLOWTHRU	RB_GUP	7,015,140	3,619,224	117,285	678,056	774,187	605,815	1,055,478	6,283	141,009	17,802
ABFUDC	RB_CWIP	(268,834)	(143,362)	(4,876)	(26,373)	(29,368)	(21,234)	(36,208)	(245)	(6,367)	(801)
INTEREST CAPITALIZATION	RB_GUP	465,437	240,126	7,782	44,987	51,365	40,194	70,028	417	9,356	1,181
CUSTOMER ADVANCES	CUST_TOTAL	1,030	669	83	54	4	0	0	0	220	0
PROVISION FOR POSSIBLE REVENUE REFUNDS	REV	82,724	32,309	1,574	9,802	10,167	9,456	17,947	90	1,180	200
PERCENT REPAIR ALLOWANCE	RB_GUP	(297,000)	(153,227)	(4,966)	(28,707)	(32,777)	(25,648)	(44,686)	(266)	(5,970)	(754)
REMOVAL COSTS	RB_GUP	(5,261,850)	(2,714,673)	(87,972)	(508,590)	(580,695)	(454,404)	(791,683)	(4,712)	(105,767)	(13,353)
DEFERRED FUEL	FUELREV	(4,802,865)	(1,601,008)	(47,334)	(421,008)	(549,101)	(656,918)	(1,489,048)	(4,948)	(27,877)	(5,623)
TAX AMORTIZATION OF POLLUTION CONTROL	PROD_DEMAND	(11,879,328)	(5,176,479)	(111,486)	(1,066,887)	(1,383,197)	(1,416,707)	(2,705,006)	(9,874)	(7,838)	(1,853)
CAPITALIZED RELOCATION COSTS	RB_GUP	(187,110)	(96,533)	(3,128)	(18,085)	(20,649)	(16,158)	(28,152)	(168)	(3,761)	(475)
MTM BOOK GAIN ABOVE THE LINE TAX DEFERRAL	PROD_ENERGY	(5,193,129)	(1,765,057)	(52,149)	(463,182)	(599,028)	(697,639)	(1,573,859)	(5,447)	(30,593)	(6,174)
PROVISION FOR WORKERS COMP	LABOR_M	(203,472)	(109,522)	(4,703)	(18,991)	(20,355)	(15,694)	(27,865)	(171)	(5,667)	(505)
ACCRUED BOOK PENSION EXPENSE	LABOR_M	673,275	362,399	15,562	62,839	67,353	51,929	92,204	565	18,753	1,671
SUPPLEMENTAL EXECUTIVE RETIREMENT	LABOR_M	20,125	10,833	465	1,878	2,013	1,552	2,756	17	561	50
ACCRUED BOOK SUPPLEMENTAL SAVINGS PLAN EXP	LABOR_M	73,185	39,393	1,692	6,831	7,321	5,645	10,023	61	2,038	182
BOOK PROVISION UNCOLLECTIBLE ACCOUNTS	CUST_TOTAL	(586,005)	(380,578)	(47,087)	(30,439)	(2,274)	(224)	(37)	(55)	(125,166)	(145)
REG ASSET ON UNREALIZED LOSS FWD CMMT	PROD_ENERGY	173,273	58,893	1,740	15,454	19,987	23,277	52,513	182	1,021	206
PROVISION FOR TRADING CREDIT RISK ABOVE THE LINE	PROD_ENERGY	57,444	19,524	577	5,124	6,626	7,717	17,409	60	338	68
AOFUDC - HR/J	BULK_TRANS	11,205	4,883	105	1,006	1,305	1,336	2,551	9	7	2
POST RETIREMENT BENEFIT PAYMENT	RB_GUP	(111,083)	(57,310)	(1,857)	(10,737)	(12,259)	(9,593)	(16,713)	(99)	(2,233)	(282)
ADVANCE RENTAL INCOME	REV_OTHER	(24,844)	(12,886)	(516)	(2,791)	(2,711)	(1,955)	(3,479)	(24)	(425)	(57)
BOOK AMORTIZATION LOSS REAQUIRED DEBT	RB_GUP	80,394	41,477	1,344	7,771	8,872	6,943	12,096	72	1,616	204
NONDEDUCTIBLE MEALS & TRAVEL EXPENSE	LABOR_M	34,482	18,560	797	3,218	3,449	2,660	4,722	29	960	86
VACATION PAY SEC 481	LABOR_M	134,841	72,580	3,117	12,585	13,489	10,400	18,466	113	3,756	335
SEC 481 3-YR ADJ PROPERTY TAX	RB_GUP	206	106	3	20	23	18	31	0	4	1
DEFERRED COMPENSATION PAYMENTS	LABOR_M	(24,856)	(13,379)	(575)	(2,320)	(2,487)	(1,917)	(3,404)	(21)	(692)	(62)
ACCRUED STATE INCOME TAX EXPENSE	REV	95,635	37,351	1,820	11,331	11,754	10,932	20,748	104	1,365	231
ACCRUED RTO CARRYING CHARGES	RB_GUP_EPIS_T	(147,206)	(62,580)	(1,342)	(13,092)	(17,129)	(18,331)	(34,538)	(120)	(59)	(14)
REG ASSET ON DEFERRED RTO COSTS	RB_GUP_EPIS_T	(75,416)	(32,061)	(688)	(6,707)	(8,775)	(9,391)	(17,694)	(61)	(30)	(7)
DEFERRED BOOK CONTRACT REVENUE	REV	(10,923)	(4,266)	(208)	(1,294)	(1,342)	(1,249)	(2,370)	(12)	(156)	(26)
DEFERRED DEMAND SIDE MANAGEMENT EXPENSE	LABOR_M	2,758,889	1,485,010	63,770	257,498	275,992	212,790	377,824	2,313	76,845	6,848
BOOK > TAX BASIS - EMA A/C 283	PROD_ENERGY	1,828,429	621,452	18,361	163,080	210,910	245,629	554,134	1,918	10,771	2,174
DEFERRED TAX GAIN INTERCO SALE EMA	PROD_ENERGY	(93,324)	(31,719)	(937)	(8,324)	(10,765)	(12,537)	(28,283)	(98)	(550)	(111)
DEFERRED TAX GAIN EPA AUCTION	PROD_ENERGY	(374,055)	(127,135)	(3,756)	(33,362)	(43,147)	(50,250)	(113,363)	(392)	(2,204)	(445)
REG ASSET UNREALIZED MTM GAIN DEFERRAL	PROD_ENERGY	3,306,097	1,123,687	33,200	294,875	381,359	444,137	1,001,964	3,468	19,476	3,931
REG ASSET DEFERRED EQUITY CARRYING	RB_GUP_EPIS_T	219,950	93,505	2,005	19,562	25,593	27,390	51,606	179	89	21
CAPITALIZED SOFTWARE COSTS TAX	RB_GUP	(10,781)	(5,562)	(180)	(1,042)	(1,190)	(931)	(1,622)	(10)	(217)	(27)
CAPITALIZED SOFTWARE COSTS BOOK	RB_GUP	1,123,198	579,476	18,779	108,564	123,956	96,997	168,993	1,006	22,577	2,850
BOOK LEASES CAPITALIZED FOR TAX	RB_GUP	(504,384)	(260,220)	(8,433)	(48,752)	(55,664)	(43,558)	(75,888)	(452)	(10,138)	(1,280)
ACCRUED SFAS 112 POST EMPLOYMENT BENEFITS	LABOR_M	(248,345)	(133,675)	(5,740)	(23,179)	(24,844)	(19,155)	(34,010)	(208)	(6,917)	(616)
BOOK DEFFERAL MERGER COSTS	REV	529,635	206,855	10,078	62,754	65,094	60,542	114,903	574	7,557	1,278
SFAS 109 DEFERRED SIT LIABILITY	REV	(7,167,903)	(2,799,507)	(136,397)	(849,288)	(880,956)	(819,350)	(1,555,061)	(7,764)	(102,279)	(17,300)
REG ASSET SFAS 109 DEFERRED SIT LIABILITY	REV	7,167,903	2,799,507	136,397	849,288	880,956	819,350	1,555,061	7,764	102,279	17,300
REG ASSET ACCRUED SFAS 112	LABOR_M	204,015	109,814	4,716	19,042	20,409	15,735	27,939	171	5,683	506
1977 - 1980 IRS AUDIT SETTLEMENT	REV	(17,736)	(6,927)	(337)	(2,101)	(2,180)	(2,027)	(3,848)	(19)	(253)	(43)
1985 - 1987 IRS AUDIT SETTLEMENT	REV	(824)	(322)	(16)	(98)	(101)	(94)	(179)	(1)	(12)	(2)
IRS AUDIT SETTLEMENTS PERM	REV	6,789	2,652	129	804	834	776	1,473	7	97	16
MANUFACTURING DEDUCTION	PROD_DEMAND	(627,096)	(273,260)	(5,885)	(56,320)	(73,017)	(74,786)	(142,794)	(521)	(414)	(98)
TOTAL SCHEDULE M ADJUSTMENTS		(18,067,702)	(7,482,979)	(189,711)	(1,586,405)	(2,054,545)	(2,187,772)	(4,403,565)	(15,672)	(138,885)	(8,168)
SCHEDULE M - ADJUSTMENT		4,834,630	2,278,880	72,733	456,681	538,229	476,989	915,659	4,489	80,314	10,656

KENTUCKY POWER COMPANY
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	METHOD	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
BONUS DEPRECIATION ADJUSTMENT FOR STATE	RB_GUP	(55,930)	(28,855)	(935)	(5,406)	(6,172)	(4,830)	(8,415)	(50)	(1,124)	(142)
STATE TAXABLE INCOME	FORMULA	(18,733,104)	(32,455,400)	849,178	7,331,209	2,528,459	2,251,180	964,764	40,419	(474,354)	231,441
STATE INCOME TAX KENTUCKY	FORMULA	(1,311,317)	(2,271,878)	59,442	513,185	176,992	157,583	67,533	2,829	(33,205)	16,201
STATE INCOME TAX OHIO	FORMULA	(28,997)	(50,238)	1,314	11,348	3,914	3,485	1,493	63	(734)	358
STATE INCOME TAX WEST VIRGINIA	FORMULA	(7,912)	(13,708)	359	3,096	1,068	951	407	17	(200)	98
TOTAL STATE INCOME TAXES		(1,348,227)	(2,335,824)	61,116	527,629	181,974	162,018	69,434	2,909	(34,139)	16,657
TAXABLE OPERATING INCOME	FORMULA	(17,328,947)	(30,090,721)	788,997	6,808,986	2,352,658	2,093,992	903,745	37,560	(439,090)	214,926
GROSS CURRENT FIT	FORMULA	(6,065,132)	(10,531,752)	276,149	2,383,145	823,430	732,897	316,311	13,146	(153,682)	75,224
FEEDBACK PRIOR ITC NORMALIZATION TAX	RB_GUP	(1,156,997)	(596,913)	(19,344)	(111,831)	(127,686)	(99,916)	(174,078)	(1,036)	(23,256)	(2,936)
CURRENT FIT AND ITC	FORMULA	(7,222,129)	(11,128,666)	256,805	2,271,314	695,745	632,981	142,232	12,110	(176,938)	72,288
DEFERRED FIT - CURRENT YEAR											
DIFIT FOR BOOK VS TAX DEPRECIATION NORMALIZED	RB_GUP	1,793,574	925,334	29,987	173,360	197,938	154,890	269,856	1,606	36,052	4,551
ABFUDC	RB_CWIP	101,807	54,291	1,846	9,987	11,122	8,041	13,712	93	2,411	303
WSEC 482 PENSION/OPEB ADJUSTMENT	LABOR_M	(72)	(39)	(2)	(7)	(7)	(6)	(10)	(0)	(2)	(0)
INTEREST CAPITALIZATION	RB_GUP	(162,904)	(84,045)	(2,724)	(15,746)	(17,978)	(14,068)	(24,510)	(146)	(3,274)	(413)
CUSTOMER ADVANCES	CUST_TOTAL	(362)	(235)	(29)	(19)	(1)	(0)	(0)	(0)	(77)	(0)
PERCENT REPAIR ALLOWANCE	RB_GUP	103,950	53,629	1,738	10,047	11,472	8,977	15,640	93	2,089	264
TAX AMORTIZATION POLLUTION CONTROL	PROD_DEMAND	4,157,765	1,811,768	39,020	373,411	484,119	495,847	946,752	3,456	2,743	649
CAPITALIZED RELOCATION COSTS	RB_GUP	65,489	33,787	1,095	6,330	7,227	5,656	9,853	59	1,316	166
MTM BOOK GAIN ABOVE THE LINE TAX DEFERRAL	PROD_ENERGY	1,817,595	617,770	18,252	162,114	209,660	244,174	550,850	1,907	10,707	2,161
PROVISION FOR WORKERS COMP	LABOR_M	71,215	38,332	1,646	6,647	7,124	5,493	9,753	60	1,984	177
ACCRUED BOOK PENSION EXPENSE	LABOR_M	(235,644)	(126,839)	(5,447)	(21,994)	(23,573)	(18,175)	(32,271)	(198)	(6,564)	(585)
SUPPLEMENTAL EXECUTIVE RETIREMENT	LABOR_M	(7,044)	(3,792)	(163)	(657)	(705)	(543)	(965)	(6)	(196)	(17)
ACCRUED BOOK SUPPLEMENTAL SAVINGS PLAN EXP	LABOR_M	(25,615)	(13,788)	(592)	(2,391)	(2,562)	(1,976)	(3,508)	(21)	(713)	(64)
POST RETIREMENT BENEFIT	RB_GUP	(253,642)	(130,858)	(4,241)	(24,516)	(27,992)	(21,904)	(38,162)	(227)	(5,098)	(644)
DEFERRED FUEL EXPENSE	FUELREV	1,681,005	560,353	16,567	147,353	192,186	229,922	521,167	1,732	9,757	1,968
PROVISION FOR POSSIBLE REVENUE REFUNDS	REV	(28,953)	(11,308)	(551)	(3,430)	(3,558)	(3,310)	(6,281)	(31)	(413)	(70)
BOOK PROVISION UNCOLLECTIBLE ACCOUNTS	CUST_TOTAL	205,103	133,203	16,480	10,654	796	78	13	19	43,808	51
REG ASSET UNREALIZED LOSS FWD CMMT	PROD_ENERGY	(60,645)	(20,612)	(609)	(5,409)	(6,995)	(8,147)	(18,379)	(64)	(357)	(72)
PROVISION FOR TRADING CREDIT RISK ABOVE THE LINE	PROD_ENERGY	(20,105)	(6,833)	(202)	(1,793)	(2,319)	(2,701)	(6,093)	(21)	(118)	(24)
DEFERRED COMPENSATION BOOK EXPENSE	LABOR_M	8,700	4,683	201	812	870	671	1,191	7	242	22
ACCRUED STATE INCOME TAX EXPENSE	REV	(33,472)	(13,073)	(637)	(3,966)	(4,114)	(3,826)	(7,262)	(36)	(478)	(81)
ACCRUED RTO CARRYING CHARGES	RB_GUP_EPIS_T	51,522	21,903	470	4,582	5,995	6,416	12,088	42	21	5
REG ASSET ON DEFERRED RTO COSTS	RB_GUP_EPIS_T	26,395	11,221	241	2,348	3,071	3,287	6,193	22	11	3
DEFERRED BOOK CONTRACT REVENUE	REV	3,823	1,493	73	453	470	437	829	4	55	9
DEFERRED DEMAND SIDE MANAGEMENT EXPENSE	LABOR_M	(965,612)	(519,754)	(22,319)	(90,124)	(96,597)	(74,477)	(132,239)	(810)	(26,896)	(2,397)
BOOK > TAX BASIS - EMA A/C 283	PROD_ENERGY	(639,950)	(217,508)	(6,426)	(57,078)	(73,818)	(85,970)	(193,947)	(671)	(3,770)	(761)
DEFERRED TAX GAIN INTERCO SALE EMA	PROD_ENERGY	32,664	11,102	328	2,913	3,768	4,388	9,899	34	192	39
DEFERRED TAX GAIN EPA AUCTION	PROD_ENERGY	130,920	44,498	1,315	11,677	15,102	17,588	39,677	137	771	156
REG ASSET UNREAL MTM GAIN DEFERRAL	PROD_ENERGY	(1,157,133)	(393,290)	(11,620)	(103,206)	(133,476)	(155,448)	(350,687)	(1,214)	(6,817)	(1,376)
REG ASSET DEFERRED EQUITY CARRYING	RB_GUP_EPIS_T	(76,982)	(32,727)	(702)	(6,847)	(8,958)	(9,586)	(18,062)	(63)	(31)	(7)
CAPITALIZED SOFTWARE COST TAX	RB_GUP	3,773	1,947	63	365	416	326	568	3	76	10
CAPITALIZED SOFTWARE COST BOOK	RB_GUP	(393,117)	(202,815)	(6,572)	(37,997)	(43,384)	(33,949)	(59,147)	(352)	(7,902)	(998)
BOOK LEASES CAPITALIZED FOR TAX	RB_GUP	176,535	91,077	2,951	17,063	19,482	15,245	26,561	158	3,548	448
ADVANCE RENTAL INCOME	REV_OTHER	8,696	4,511	181	977	949	684	1,218	8	149	20
BOOK AMORTIZATION LOSS REAQUIRED DEBT	RB_GUP	(28,139)	(14,517)	(470)	(2,720)	(3,105)	(2,430)	(4,234)	(25)	(566)	(71)
ACCRUED SFAS 112 POST EMPLOYMENT BENEFITS	LABOR_M	86,923	46,787	2,009	8,113	8,696	6,704	11,904	73	2,421	216
BOOK DEFFERAL MERGER COSTS	REV	(185,372)	(72,399)	(3,527)	(21,964)	(22,783)	(21,190)	(40,216)	(201)	(2,645)	(447)
REG ASSET ACCRUED SFAS 112	LABOR_M	(71,407)	(38,436)	(1,651)	(6,665)	(7,143)	(5,508)	(9,779)	(60)	(1,989)	(177)
1977 - 1980 IRS AUDIT SETTLEMENT	REV	6,208	2,425	118	736	763	710	1,347	7	89	15
1985 - 1987 IRS AUDIT SETTLEMENT	REV	288	112	5	34	35	33	62	0	4	1
DEFERRED VACATION ACCRUAL	LABOR_M	(47,195)	(25,403)	(1,091)	(4,405)	(4,721)	(3,640)	(6,463)	(40)	(1,315)	(117)
FEDERAL INCOME TAX - DEFERRED - ADJUSTMENT		(1,338,731)	(613,883)	(19,433)	(125,564)	(149,471)	(137,025)	(268,589)	(1,253)	(20,716)	(2,797)
TOTAL CURRENT YEAR DFIT		4,801,854	1,928,073	45,578	413,478	547,999	605,689	1,228,332	4,082	28,511	113

KENTUCKY POWER COMPANY
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	METHOD	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
DEFERRED FIT - PRIOR YEAR											
TAXES CAPITALIZED	RB_GUP	(63,817)	(32,821)	(1,064)	(6,149)	(7,021)	(5,494)	(9,572)	(57)	(1,279)	(161)
PENSIONS CAPITALIZED	RB_GUP	(8,538)	(4,405)	(143)	(825)	(942)	(737)	(1,285)	(8)	(172)	(22)
SAVING PLAN CAPITALIZED	RB_GUP	(4,055)	(2,092)	(68)	(392)	(448)	(350)	(610)	(4)	(82)	(10)
ABFUDC	RB_CWIP	(519,030)	(276,784)	(9,413)	(50,918)	(56,700)	(40,996)	(69,906)	(473)	(12,293)	(1,546)
INTEREST CAPITALIZED	RB_GUP	249,355	128,646	4,169	24,102	27,519	21,534	37,517	223	5,012	633
ADR REPAIR ALLOWANCE	RB_GUP	(387,726)	(200,034)	(6,482)	(37,476)	(42,789)	(33,483)	(58,336)	(347)	(7,794)	(984)
BOOK VS TAX DEPRECIATION	RB_GUP	(506,680)	(261,404)	(8,471)	(48,974)	(55,917)	(43,756)	(76,234)	(454)	(10,185)	(1,286)
TOTAL PRIOR YEAR DFIT		(1,240,291)	(648,894)	(21,472)	(120,632)	(136,298)	(103,283)	(178,425)	(1,119)	(26,791)	(3,377)
FEDERAL INCOME TAXES	FORMULA	(3,660,566)	(9,849,487)	280,912	2,564,160	1,107,446	1,135,386	1,192,139	15,073	(175,219)	69,024
TOTAL INCOME TAXES		(5,008,792)	(12,185,312)	342,027	3,091,789	1,289,420	1,297,404	1,261,573	17,982	(209,358)	85,681
TOTAL EXPENSES	FORMULA	318,884,131	136,148,029	5,554,374	33,115,817	36,727,256	34,352,789	67,363,107	317,249	4,671,108	634,401
NET OPERATING INCOME	FORMULA	27,172,622	(962,193)	1,086,295	8,030,003	5,822,617	5,081,693	7,483,946	58,995	356,607	214,658
AFUDC OFFSET											
PRODUCTION	PROD_DEMAND	400,313	174,438	3,757	35,952	46,611	47,741	91,154	333	264	62
TRANSMISSION	TRANS_TOTAL	90,711	38,559	827	8,067	10,555	11,298	21,286	74	37	9
DISTRIBUTION	RB_GUP_EPIS_D	101,043	68,015	3,033	11,178	10,119	2,128	94	105	5,656	714
GENERAL	LABOR_M	16,455	8,857	380	1,536	1,646	1,269	2,253	14	458	41
AFUDC OFFSET		608,522	289,870	7,997	56,733	68,932	62,436	114,787	525	6,415	826
AFUDC OFFSET ADJUSTMENT - ADJUSTMENT		625,507	297,961	8,221	58,317	70,856	64,179	117,991	540	6,594	849
ADJUSTED NET OPERATING INCOME	FORMULA	28,406,651	(374,363)	1,102,513	8,145,054	5,962,405	5,208,308	7,716,724	60,060	369,617	216,333

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED JUNE 30, 2005

	METHOD	CATEGORY	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
REVENUE REQUIREMENT ANALYSIS												
TOTAL RATE BASE			858,443,759	437,647,616	14,341,548	82,568,918	95,181,830	75,008,460	133,220,660	787,445	17,472,010	2,215,273
ADJUSTED NET OPERATING INCOME	FORMULA		28,406,651	-374,363	1,102,513	8,145,054	5,962,405	5,208,308	7,716,724	60,060	369,617	216,333
CURRENT RATE OF RETURN			3.31%	-0.09%	7.69%	9.86%	6.26%	6.94%	5.79%	7.63%	2.12%	9.77%
TOTAL EXPENSES	FORMULA		318,884,131	136,148,029	5,554,374	33,115,817	36,727,256	34,352,789	67,363,107	317,249	4,671,108	634,401
TOTAL OPERATING REVENUE	FORMULA		346,056,753	135,185,836	6,640,669	41,145,820	42,549,874	39,434,482	74,847,053	376,244	5,027,716	849,059
LESS:												
OTHER OPERATING REVENUE	FORMULA		8,713,065	5,095,871	243,958	1,095,981	910,611	411,105	662,398	9,207	250,747	33,187
SALES OF ELECTRICITY	FORMULA		337,343,688	130,089,965	6,396,711	40,049,839	41,639,263	39,023,377	74,184,655	367,037	4,776,969	815,872
PROPOSED RATE OF RETURN			7.84%	4.79%	11.78%	13.74%	10.50%	11.11%	10.08%	11.73%	6.77%	13.65%
REQUIRED INCOME	FORMULA		67,308,233	20,943,902	1,689,627	11,345,502	9,994,427	8,334,800	13,422,972	92,344	1,182,241	302,419
INCOME INCREASE	FORMULA		38,901,582	21,318,265	587,115	3,200,448	4,032,022	3,126,491	5,706,247	32,284	812,624	86,086
GROSS REVENUE CONVERSION FACTOR			1.665645									
PROPOSED REVENUE INCREASE			64,796,239	35,508,669	977,925	5,330,812	6,715,919	5,207,626	9,504,584	53,773	1,353,543	143,388
% REVENUE INCREASE			19.21%	27.30%	15.29%	13.31%	16.13%	13.34%	12.81%	14.65%	28.33%	17.57%
TOTAL REVENUE REQUIRED	FORMULA		410,852,992	170,694,505	7,618,594	46,476,632	49,265,793	44,642,108	84,351,637	430,017	6,381,259	992,447
LESS:												
OTHER OPERATING REVENUE	FORMULA		8,713,065	5,095,871	243,958	1,095,981	910,611	411,105	662,398	9,207	250,747	33,187
REQUIRED RATE REVENUE	FORMULA		402,139,927	165,598,634	7,374,636	45,380,651	48,355,182	44,231,003	83,689,239	420,810	6,130,512	959,260
REQUIRED RATE REVENUE	FORMULA	PRODUCTION	144,091,951	55,603,598	1,507,652	15,122,633	18,020,086	18,757,119	34,828,547	134,140	91,656	26,519
		BULKTRAN	29,446,720	9,192,834	351,470	3,778,773	4,048,576	4,315,961	7,703,598	31,577	17,251	6,681
		SUBTRAN	19,172,135	5,563,461	208,781	2,360,227	2,593,012	3,088,812	5,338,591	19,251	0	0
		DISTPRI	40,750,475	24,087,467	820,148	7,248,571	6,552,830	1,834,998	0	65,735	109,511	31,216
		DISTSEC	25,863,796	17,732,952	802,645	4,145,821	2,851,291	0	0	41,618	232,240	57,230
		ENERGY	116,572,944	38,457,396	1,210,677	10,710,708	13,646,927	15,864,860	35,725,679	125,591	688,282	142,824
		CUSTOMER	26,241,905	14,960,925	2,473,264	2,013,917	642,460	369,253	92,824	2,898	4,991,573	694,790
		Total	402,139,927	165,598,634	7,374,636	45,380,651	48,355,182	44,231,003	83,689,239	420,810	6,130,512	959,260
	DEMAND		259,325,078	112,180,313	3,690,695	32,656,026	34,065,795	27,996,890	47,870,736	292,321	450,657	121,647
	ENERGY		116,572,944	38,457,396	1,210,677	10,710,708	13,646,927	15,864,860	35,725,679	125,591	688,282	142,824
	CUSTOMER		26,241,905	14,960,925	2,473,264	2,013,917	642,460	369,253	92,824	2,898	4,991,573	694,790
			402,139,927	165,598,634	7,374,636	45,380,651	48,355,182	44,231,003	83,689,239	420,810	6,130,512	959,260

KENTUCKY POWER COMPANY
12 CP CLASS COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2005

ALLOCATION METHOD	FUNCTIONAL FACTOR	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP TOD	MW	OL	SL
BULK_TRANS	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	1.0000000	0.4357552	0.0093849	0.0898104	0.1164374	0.1192582	0.2277070	0.0008312	0.0006598	0.0001560
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.4357552	0.0093849	0.0898104	0.1164374	0.1192582	0.2277070	0.0008312	0.0006598	0.0001560
CUST_902	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.7937733	0.0982092	0.0953766	0.0108935	0.0014012	0.0002308	0.0001154	0.0000000	0.0000000
	Total	1.0000000	0.7937733	0.0982092	0.0953766	0.0108935	0.0014012	0.0002308	0.0001154	0.0000000	0.0000000
CUST_903	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.7751073	0.0679457	0.0439236	0.0032807	0.0003232	0.0000531	0.0000799	0.1090776	0.0002090
	Total	1.0000000	0.7751073	0.0679457	0.0439236	0.0032807	0.0003232	0.0000531	0.0000799	0.1090776	0.0002090
CUST_DEP	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.7239590	0.0268620	0.1352471	0.0554240	0.0364802	0.0141050	0.0000000	0.0079228	0.0000000
	Total	1.0000000	0.7239590	0.0268620	0.1352471	0.0554240	0.0364802	0.0141050	0.0000000	0.0079228	0.0000000
CUST_TOTAL	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.6494450	0.0803523	0.0519437	0.0038798	0.0003821	0.0000629	0.0000944	0.2135924	0.0002473
	Total	1.0000000	0.6494450	0.0803523	0.0519437	0.0038798	0.0003821	0.0000629	0.0000944	0.2135924	0.0002473

KENTUCKY POWER COMPANY
12 CP CLASS COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2005

ALLOCATION METHOD	FUNCTIONAL FACTOR	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP_TOD	MW	OL	SL
DIST_CPD	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	1.0000000	0.6763726	0.0150810	0.1289029	0.1359246	0.0397555	0.0000000	0.0012490	0.0022515	0.0004630
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.6763726	0.0150810	0.1289029	0.1359246	0.0397555	0.0000000	0.0012490	0.0022515	0.0004630
DIST_METERS	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.4529234	0.1810963	0.1484322	0.1210214	0.0765492	0.0197646	0.0002129	0.0000000	0.0000000
	Total	1.0000000	0.4529234	0.1810963	0.1484322	0.1210214	0.0765492	0.0197646	0.0002129	0.0000000	0.0000000
DIST_OHLINES	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.6610000	0.4470823	0.0099685	0.0852048	0.0898461	0.0262784	0.0000000	0.0008256	0.0014882	0.0003061
	DISTSEC	0.3390000	0.2614110	0.0077765	0.0367361	0.0292418	0.0000000	0.0000000	0.0003990	0.0029353	0.0005003
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.7084933	0.0177450	0.1219409	0.1190879	0.0262784	0.0000000	0.0012246	0.0044236	0.0008063
DIST_OL	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	1.0000000	0.0000000
	Total	1.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	1.0000000	0.0000000
DIST_PCUST	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.6498833	0.0804065	0.0518798	0.0036125	0.0001395	0.0000000	0.0000945	0.2137365	0.0002474
	Total	1.0000000	0.6498833	0.0804065	0.0518798	0.0036125	0.0001395	0.0000000	0.0000945	0.2137365	0.0002474

KENTUCKY POWER COMPANY
12 CP CLASS COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2005

ALLOCATION METHOD	FUNCTIONAL FACTOR	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP TOD	MW	OL	SL
DIST_POLES	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.5620000	0.3801214	0.0084755	0.0724434	0.0763896	0.0223426	0.0000000	0.0007019	0.0012653	0.0002602
	DISTSEC	0.4380000	0.3377523	0.0100475	0.0474643	0.0377814	0.0000000	0.0000000	0.0005155	0.0037926	0.0006464
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.7178737	0.0185230	0.1199077	0.1141710	0.0223426	0.0000000	0.0012175	0.0050579	0.0009066
DIST_SERV	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.6505183	0.0804851	0.0515567	0.0031522	0.0000000	0.0000000	0.0000946	0.2139454	0.0002477
	Total	1.0000000	0.6505183	0.0804851	0.0515567	0.0031522	0.0000000	0.0000000	0.0000946	0.2139454	0.0002477
DIST_SL	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	1.0000000
	Total	1.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	1.0000000
DIST_TRANSF	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.2690000	0.2074323	0.0061707	0.0291504	0.0232037	0.0000000	0.0000000	0.0003166	0.0023292	0.0003970
	DISTSEC	0.7310000	0.5636916	0.0167688	0.0792155	0.0630553	0.0000000	0.0000000	0.0008604	0.0063296	0.0010788
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.7711240	0.0229395	0.1083660	0.0862590	0.0000000	0.0000000	0.0011771	0.0086588	0.0014757
DIST_UGLINES	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.6250000	0.4227329	0.0094256	0.0805643	0.0849528	0.0248472	0.0000000	0.0007806	0.0014072	0.0002894
	DISTSEC	0.3750000	0.2891715	0.0086023	0.0406372	0.0323471	0.0000000	0.0000000	0.0004414	0.0032471	0.0005534
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.7119044	0.0180279	0.1212015	0.1173000	0.0248472	0.0000000	0.0012220	0.0046542	0.0008428

KENTUCKY POWER COMPANY
12 CP CLASS COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2005

ALLOCATION METHOD	FUNCTIONAL FACTOR	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP TOD	MW	OL	SL
EXP_OM_CUSTACCT	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.7804042	0.0759681	0.0575973	0.0053054	0.0006099	0.0001004	0.0000893	0.0797721	0.0001533
	Total	1.0000000	0.7804042	0.0759681	0.0575973	0.0053054	0.0006099	0.0001004	0.0000893	0.0797721	0.0001533
EXP_OM_CUSTSERV	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.6494450	0.0803523	0.0519437	0.0038798	0.0003821	0.0000629	0.0000944	0.2135924	0.0002473
	Total	1.0000000	0.6494450	0.0803523	0.0519437	0.0038798	0.0003821	0.0000629	0.0000944	0.2135924	0.0002473
EXP_OM_DIST	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.5469682	0.3719113	0.0084111	0.0700816	0.0733206	0.0209239	0.0000000	0.0006817	0.0013638	0.0002742
	DISTSEC	0.3356158	0.2588014	0.0076989	0.0363693	0.0289499	0.0000000	0.0000000	0.0003950	0.0029060	0.0004953
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.1174160	0.0418476	0.0108175	0.0083977	0.0055690	0.0034544	0.0008913	0.0000127	0.0398032	0.0066225
	Total	1.0000000	0.6725603	0.0269275	0.1148486	0.1078395	0.0243783	0.0008913	0.0010894	0.0440731	0.0073920
EXP_OM_TRAN	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.6100000	0.2658107	0.0057248	0.0547844	0.0710268	0.0727475	0.1389013	0.0005070	0.0004025	0.0000952
	SUBTRAN	0.3900000	0.1592653	0.0033904	0.0341498	0.0453324	0.0518017	0.0957522	0.0003082	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.4250760	0.0091152	0.0889342	0.1163592	0.1245492	0.2346535	0.0008152	0.0004025	0.0000952
EXP_OM	PRODUCTION	0.3385316	0.1475103	0.0031771	0.0304043	0.0394180	0.0403742	0.0770902	0.0002814	0.0002234	0.0000528
	BULKTRAN	0.0057688	0.0025105	0.0000541	0.0005184	0.0006718	0.0006887	0.0013157	0.0000048	0.0000038	0.0000009
	SUBTRAN	0.0036881	0.0015042	0.0000321	0.0003231	0.0004288	0.0004904	0.0009066	0.0000029	0.0000000	0.0000000
	DISTPRI	0.0623823	0.0424151	0.0009594	0.0079938	0.0083629	0.0023866	0.0000000	0.0000778	0.0001555	0.0000313
	DISTSEC	0.0382785	0.0295164	0.0008782	0.0041487	0.0033022	0.0000000	0.0000000	0.0000451	0.0003314	0.0000565
	ENERGY	0.4847824	0.1647694	0.0048682	0.0432384	0.0559197	0.0651251	0.1469209	0.0005085	0.0028558	0.0005764
	CUSTOMER	0.0665683	0.0451531	0.0053111	0.0039725	0.0009052	0.0004246	0.0001067	0.0000062	0.0099246	0.0007643
	Total	1.0000000	0.4333790	0.0152802	0.0905993	0.1090086	0.1094896	0.2263401	0.0009267	0.0134945	0.0014821

KENTUCKY POWER COMPANY
12 CP CLASS COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2005

ALLOCATION METHOD	FUNCTIONAL FACTOR	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP TOD	MW	OL	SL
FORT	PRODUCTION	1.0000000	0.5869647	0.0506073	0.1969230	0.0922638	0.0643106	0.0000000	0.0000000	0.0089305	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.5869647	0.0506073	0.1969230	0.0922638	0.0643106	0.0000000	0.0000000	0.0089305	0.0000000
FUELREV	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	1.0000000	0.3333443	0.0098553	0.0876577	0.1143279	0.1367764	0.3100332	0.0010302	0.0058043	0.0011707
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.3333443	0.0098553	0.0876577	0.1143279	0.1367764	0.3100332	0.0010302	0.0058043	0.0011707
LABOR_M	PRODUCTION	0.4074631	0.1775542	0.0038240	0.0365944	0.0474439	0.0485933	0.0927822	0.0003387	0.0002688	0.0000636
	BULKTRAN	0.0440370	0.0191894	0.0004133	0.0039550	0.0051276	0.0052518	0.0100275	0.0000366	0.0000291	0.0000069
	SUBTRAN	0.0281548	0.0114977	0.0002448	0.0024653	0.0032726	0.0037397	0.0069125	0.0000223	0.0000000	0.0000000
	DISTPRI	0.1690486	0.1149447	0.0025996	0.0216598	0.0226608	0.0064668	0.0000000	0.0002107	0.0004215	0.0000847
	DISTSEC	0.1037271	0.0799864	0.0023794	0.0112405	0.0089474	0.0000000	0.0000000	0.0001221	0.0008982	0.0001531
	ENERGY	0.0888882	0.0302116	0.0008926	0.0079281	0.0102533	0.0119411	0.0269390	0.0000932	0.0005236	0.0001057
	CUSTOMER	0.1586811	0.1048797	0.0127607	0.0094908	0.0023317	0.0011361	0.0002868	0.0000150	0.0257123	0.0020681
	Total	1.0000000	0.5382637	0.0231143	0.0933339	0.1000373	0.0771288	0.1369480	0.0008385	0.0278535	0.0024820
PROD_DEMAND	PRODUCTION	1.0000000	0.4357552	0.0093849	0.0898104	0.1164374	0.1192582	0.2277070	0.0008312	0.0006598	0.0001560
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.4357552	0.0093849	0.0898104	0.1164374	0.1192582	0.2277070	0.0008312	0.0006598	0.0001560
PROD_ENERGY	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	1.0000000	0.3398832	0.0100420	0.0891913	0.1153502	0.1343389	0.3030656	0.0010489	0.0058910	0.0011889
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.3398832	0.0100420	0.0891913	0.1153502	0.1343389	0.3030656	0.0010489	0.0058910	0.0011889

KENTUCKY POWER COMPANY
12 CP CLASS COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2005

ALLOCATION METHOD	FUNCTIONAL FACTOR	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP TOD	MW	OL	SL
RATEBASE	PRODUCTION	0.3228279	0.1396895	0.0030028	0.0287892	0.0377819	0.0387440	0.0742834	0.0002716	0.0002145	0.0000510
	BULKTRAN	0.1668512	0.0722194	0.0015513	0.0148823	0.0195214	0.0200203	0.0383790	0.0001403	0.0001108	0.0000263
	SUBTRAN	0.1061373	0.0430094	0.0009132	0.0092206	0.0123825	0.0141922	0.0263347	0.0000848	0.0000000	0.0000000
	DISTPRI	0.1707929	0.1168976	0.0026967	0.0216350	0.0225963	0.0061571	0.0000000	0.0002154	0.0004973	0.0000976
	DISTSEC	0.1203478	0.0926716	0.0027507	0.0130470	0.0105005	0.0000000	0.0000000	0.0001439	0.0010537	0.0001804
	ENERGY	0.0523527	0.0177784	0.0005292	0.0046704	0.0060470	0.0070286	0.0158720	0.0000550	0.0003098	0.0000622
	CUSTOMER	0.0606902	0.0275493	0.0052625	0.0039398	0.0020476	0.0012351	0.0003195	0.0000063	0.0181669	0.0021631
	Total	1.0000000	0.5098151	0.0167064	0.0961844	0.1108772	0.0873773	0.1551886	0.0009173	0.0203531	0.0025806
RB_CWIP	PRODUCTION	0.5160022	0.2248507	0.0048426	0.0463424	0.0600819	0.0615375	0.1174973	0.0004289	0.0003405	0.0000805
	BULKTRAN	0.0403130	0.0175666	0.0003783	0.0036205	0.0046939	0.0048077	0.0091795	0.0000335	0.0000266	0.0000063
	SUBTRAN	0.0257739	0.0105253	0.0002241	0.0022569	0.0029959	0.0034234	0.0063280	0.0000204	0.0000000	0.0000000
	DISTPRI	0.2008082	0.1377520	0.0031885	0.0254663	0.0262827	0.0071731	0.0000000	0.0002493	0.0005827	0.0001136
	DISTSEC	0.1420991	0.1095760	0.0032597	0.0153987	0.0122573	0.0000000	0.0000000	0.0001673	0.0012304	0.0002097
	ENERGY	0.0042986	0.0014610	0.0000432	0.0003834	0.0004958	0.0005775	0.0013027	0.0000045	0.0000253	0.0000051
	CUSTOMER	0.0707051	0.0315406	0.0061998	0.0046335	0.0024338	0.0014676	0.0003786	0.0000073	0.0214795	0.0025643
	Total	1.0000000	0.5332722	0.0181361	0.0981016	0.1092414	0.0789867	0.1346862	0.0009111	0.0236850	0.0029796
RB_GUP_EPIS_D	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.4904759	0.3365862	0.0077984	0.0621743	0.0641298	0.0174676	0.0000000	0.0006089	0.0014317	0.0002788
	DISTSEC	0.3490358	0.2691499	0.0080067	0.0378236	0.0301075	0.0000000	0.0000000	0.0004108	0.0030222	0.0005151
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.1604883	0.0673937	0.0142144	0.0106290	0.0059099	0.0035968	0.0009287	0.0000167	0.0515245	0.0062746
	Total	1.0000000	0.6731298	0.0300195	0.1106269	0.1001472	0.0210645	0.0009287	0.0010365	0.0559784	0.0070685
RB_GUP_EPIS_G	PRODUCTION	0.4074631	0.1775542	0.0038240	0.0365944	0.0474439	0.0485933	0.0927822	0.0003387	0.0002688	0.0000636
	BULKTRAN	0.0440370	0.0191894	0.0004133	0.0039550	0.0051276	0.0052518	0.0100275	0.0000366	0.0000291	0.0000069
	SUBTRAN	0.0281548	0.0114977	0.0002448	0.0024653	0.0032726	0.0037397	0.0069125	0.0000223	0.0000000	0.0000000
	DISTPRI	0.1690486	0.1149447	0.0025996	0.0216598	0.0226608	0.0064668	0.0000000	0.0002107	0.0004215	0.0000847
	DISTSEC	0.1037271	0.0799864	0.0023794	0.0112405	0.0089474	0.0000000	0.0000000	0.0001221	0.0008982	0.0001531
	ENERGY	0.0888882	0.0302116	0.0008926	0.0079281	0.0102533	0.0119411	0.0269390	0.0000932	0.0005236	0.0001057
	CUSTOMER	0.1586811	0.1048797	0.0127607	0.0094908	0.0023317	0.0011361	0.0002868	0.0000150	0.0257123	0.0020681
	Total	1.0000000	0.5382637	0.0231143	0.0933339	0.1000373	0.0771288	0.1369480	0.0008385	0.0278535	0.0024820
RB_GUP_EPIS_P	PRODUCTION	1.0000000	0.4357552	0.0093849	0.0898104	0.1164374	0.1192582	0.2277070	0.0008312	0.0006598	0.0001560
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.4357552	0.0093849	0.0898104	0.1164374	0.1192582	0.2277070	0.0008312	0.0006598	0.0001560

KENTUCKY POWER COMPANY
12 CP CLASS COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2005

ALLOCATION METHOD	FUNCTIONAL FACTOR	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP TOD	MW	OL	SL
RB_GUP_EPIS_T	PRODUCTION	0.0041242	0.0017972	0.0000387	0.0003704	0.0004802	0.0004918	0.0009391	0.0000034	0.0000027	0.0000006
	BULKTRAN	0.6074842	0.2647144	0.0057012	0.0545584	0.0707339	0.0724475	0.1383284	0.0005049	0.0004008	0.0000948
	SUBTRAN	0.3883915	0.1586085	0.0033764	0.0340090	0.0451454	0.0515880	0.0953573	0.0003069	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.4251200	0.0091163	0.0889378	0.1163595	0.1245274	0.2346248	0.0008153	0.0004035	0.0000954
RB_GUP_EPIS	PRODUCTION	0.3562084	0.1552196	0.0033430	0.0319912	0.0414760	0.0424808	0.0811111	0.0002961	0.0002350	0.0000556
	BULKTRAN	0.1773850	0.0772964	0.0016647	0.0159310	0.0206542	0.0211546	0.0403918	0.0001474	0.0001170	0.0000277
	SUBTRAN	0.1125831	0.0459759	0.0009787	0.0098582	0.0130863	0.0149538	0.0276412	0.0000890	0.0000000	0.0000000
	DISTPRI	0.1703700	0.1168763	0.0027056	0.0216052	0.0222965	0.0060839	0.0000000	0.0002115	0.0004947	0.0000964
	DISTSEC	0.1206299	0.0930206	0.0027672	0.0130722	0.0104054	0.0000000	0.0000000	0.0001420	0.0010445	0.0001780
	ENERGY	0.0032720	0.0011121	0.0000329	0.0002918	0.0003774	0.0004396	0.0009916	0.0000034	0.0000193	0.0000039
	CUSTOMER	0.0595516	0.0264153	0.0052268	0.0039066	0.0020637	0.0012456	0.0003214	0.0000061	0.0181902	0.0021760
	Total	1.0000000	0.5159162	0.0167189	0.0966562	0.1103595	0.0863583	0.1504572	0.0008956	0.0201007	0.0025376
RB_GUP	PRODUCTION	0.3562084	0.1552196	0.0033430	0.0319912	0.0414760	0.0424808	0.0811111	0.0002961	0.0002350	0.0000556
	BULKTRAN	0.1773850	0.0772964	0.0016647	0.0159310	0.0206542	0.0211546	0.0403918	0.0001474	0.0001170	0.0000277
	SUBTRAN	0.1125831	0.0459759	0.0009787	0.0098582	0.0130863	0.0149538	0.0276412	0.0000890	0.0000000	0.0000000
	DISTPRI	0.1703700	0.1168763	0.0027056	0.0216052	0.0222965	0.0060839	0.0000000	0.0002115	0.0004947	0.0000964
	DISTSEC	0.1206299	0.0930206	0.0027672	0.0130722	0.0104054	0.0000000	0.0000000	0.0001420	0.0010445	0.0001780
	ENERGY	0.0032720	0.0011121	0.0000329	0.0002918	0.0003774	0.0004396	0.0009916	0.0000034	0.0000193	0.0000039
	CUSTOMER	0.0595516	0.0264153	0.0052268	0.0039066	0.0020637	0.0012456	0.0003214	0.0000061	0.0181902	0.0021760
	Total	1.0000000	0.5159162	0.0167189	0.0966562	0.1103595	0.0863583	0.1504572	0.0008956	0.0201007	0.0025376
RB_WORKCAP_CASH	PRODUCTION	0.2765234	0.1204922	0.0025951	0.0248351	0.0321978	0.0329787	0.0629690	0.0002298	0.0001824	0.0000431
	BULKTRAN	0.0037635	0.0016378	0.0000353	0.0003382	0.0004383	0.0004493	0.0008583	0.0000031	0.0000025	0.0000006
	SUBTRAN	0.0024061	0.0009813	0.0000209	0.0002108	0.0002797	0.0003199	0.0005915	0.0000019	0.0000000	0.0000000
	DISTPRI	0.0406977	0.0276712	0.0006259	0.0052151	0.0054559	0.0015570	0.0000000	0.0000507	0.0001015	0.0000204
	DISTSEC	0.0249726	0.0192563	0.0005729	0.0027066	0.0021543	0.0000000	0.0000000	0.0000294	0.0002162	0.0000369
	ENERGY	0.6082081	0.2067197	0.0061076	0.0542469	0.0701569	0.0817060	0.1843270	0.0006380	0.0035829	0.0007231
	CUSTOMER	0.0434286	0.0294575	0.0034649	0.0025916	0.0005906	0.0002770	0.0000696	0.0000041	0.0064747	0.0004986
	Total	1.0000000	0.4062161	0.0134228	0.0901443	0.1112735	0.1172879	0.2488154	0.0009570	0.0105603	0.0013227
REV_OTHER	PRODUCTION	0.1137082	0.0667427	0.0057545	0.0223918	0.0104912	0.0073126	0.0000000	0.0000000	0.0010155	0.0000000
	BULKTRAN	0.0080915	0.0035259	0.0000759	0.0007267	0.0009422	0.0009650	0.0018425	0.0000067	0.0000053	0.0000013
	SUBTRAN	0.0051733	0.0021126	0.0000450	0.0004530	0.0006013	0.0006871	0.0012701	0.0000041	0.0000000	0.0000000
	DISTPRI	0.2212912	0.1507475	0.0034262	0.0282927	0.0295169	0.0083477	0.0000000	0.0002756	0.0005707	0.0001139
	DISTSEC	0.1651084	0.1273191	0.0037875	0.0178921	0.0142421	0.0000000	0.0000000	0.0001943	0.0014296	0.0002437
	ENERGY	0.4510866	0.1533168	0.0045298	0.0402330	0.0520329	0.0605985	0.1367088	0.0004732	0.0026573	0.0005363
	CUSTOMER	0.0355407	0.0149246	0.0031478	0.0023538	0.0013088	0.0007965	0.0002057	0.0000037	0.0114103	0.0013895
	Total	1.0000000	0.5186892	0.0207667	0.1123431	0.1091353	0.0787074	0.1400271	0.0009576	0.0170888	0.0022847

KENTUCKY POWER COMPANY
12 CP CLASS COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2005

ALLOCATION METHOD	FUNCTIONAL FACTOR	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP TOD	MW	OL	SL
REV	PRODUCTION	0.9671540	0.3738124	0.0184725	0.1151512	0.1192471	0.1116624	0.2117584	0.0010477	0.0136734	0.0023289
	BULKTRAN	0.0002999	0.0001307	0.0000028	0.0000269	0.0000349	0.0000358	0.0000683	0.0000002	0.0000002	0.0000000
	SUBTRAN	0.0001917	0.0000783	0.0000017	0.0000168	0.0000223	0.0000255	0.0000471	0.0000002	0.0000000	0.0000000
	DISTPRI	0.0082011	0.0055867	0.0001270	0.0010485	0.0010939	0.0003094	0.0000000	0.0000102	0.0000212	0.0000042
	DISTSEC	0.0061189	0.0047185	0.0001404	0.0006631	0.0005278	0.0000000	0.0000000	0.0000072	0.0000530	0.0000090
	ENERGY	0.0167173	0.0056819	0.0001679	0.0014910	0.0019283	0.0022458	0.0050664	0.0000175	0.0000985	0.0000199
	CUSTOMER	0.0013171	0.0005531	0.0001167	0.0000872	0.0000485	0.0000295	0.0000076	0.0000001	0.0004229	0.0000515
	Total	1.0000000	0.3905615	0.0190289	0.1184848	0.1229029	0.1143083	0.2169478	0.0010832	0.0142691	0.0024136
REVSALES	PRODUCTION	1.0000000	0.3861665	0.0186279	0.1185679	0.1230727	0.1160328	0.2200355	0.0010843	0.0139858	0.0024265
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.3861665	0.0186279	0.1185679	0.1230727	0.1160328	0.2200355	0.0010843	0.0139858	0.0024265
REVYEC	PRODUCTION	1.0000000	-0.5408151	0.5961799	0.3835715	0.7455874	-0.4967610	0.0000000	0.0074670	0.3161374	-0.0113671
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	-0.5408151	0.5961799	0.3835715	0.7455874	-0.4967610	0.0000000	0.0074670	0.3161374	-0.0113671
TDOMX	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0156428	0.0068164	0.0001468	0.0014049	0.0018214	0.0018655	0.0035620	0.0000130	0.0000103	0.0000024
	SUBTRAN	0.0100011	0.0040842	0.0000869	0.0008757	0.0011625	0.0013284	0.0024555	0.0000079	0.0000000	0.0000000
	DISTPRI	0.5329418	0.3623741	0.0081954	0.0682844	0.0714404	0.0203873	0.0000000	0.0006642	0.0013289	0.0002671
	DISTSEC	0.3270093	0.2521647	0.0075014	0.0354367	0.0282075	0.0000000	0.0000000	0.0003849	0.0028315	0.0004826
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.1144050	0.0407745	0.0105401	0.0081824	0.0054262	0.0033659	0.0008685	0.0000124	0.0387825	0.0064527
	Total	1.0000000	0.6662139	0.0264707	0.1141841	0.1080579	0.0269471	0.0068859	0.0010824	0.0429532	0.0072048
TDPLANT	PRODUCTION	0.0019008	0.0008283	0.0000178	0.0001707	0.0002213	0.0002267	0.0004328	0.0000016	0.0000013	0.0000003
	BULKTRAN	0.2820506	0.1229050	0.0026470	0.0253311	0.0328412	0.0336368	0.0642249	0.0002344	0.0001861	0.0000440
	SUBTRAN	0.1790004	0.0730988	0.0015561	0.0156739	0.0208064	0.0237757	0.0439479	0.0001415	0.0000000	0.0000000
	DISTPRI	0.2634092	0.1807630	0.0041881	0.0333906	0.0344408	0.0093810	0.0000000	0.0003270	0.0007689	0.0001498
	DISTSEC	0.1874491	0.1445465	0.0043000	0.0203131	0.0161692	0.0000000	0.0000000	0.0002206	0.0016231	0.0002766
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0861900	0.0361937	0.0076338	0.0057083	0.0031739	0.0019317	0.0004987	0.0000090	0.0276711	0.0033698
	Total	1.0000000	0.5583353	0.0203429	0.1005877	0.1076529	0.0689518	0.1091043	0.0009341	0.0302505	0.0038404

KENTUCKY POWER COMPANY
12 CP CLASS COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2005

ALLOCATION METHOD	FUNCTIONAL FACTOR	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP TOD	MW	OL	SL
TOTMXEXP	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.5823474	0.3950542	0.0088794	0.0748126	0.0785419	0.0226605	0.0000000	0.0007264	0.0013903	0.0002821
	DISTSEC	0.3701021	0.2853946	0.0084900	0.0401065	0.0319246	0.0000000	0.0000000	0.0004356	0.0032046	0.0005462
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0475505	0.0024321	0.0009724	0.0007970	0.0006498	0.0004110	0.0001061	0.0000011	0.0356097	0.0065711
	Total	1.0000000	0.6828808	0.0183418	0.1157161	0.1111163	0.0230715	0.0001061	0.0011632	0.0402047	0.0073994
TOTOHLINES	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.6062227	0.4100325	0.0091424	0.0781438	0.0824006	0.0241007	0.0000000	0.0007572	0.0013649	0.0002807
	DISTSEC	0.3937773	0.3036511	0.0090331	0.0426721	0.0339668	0.0000000	0.0000000	0.0004635	0.0034096	0.0005811
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.7136836	0.0181755	0.1208159	0.1163674	0.0241007	0.0000000	0.0012206	0.0047746	0.0008618
TOTOX234	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.7804042	0.0759681	0.0575973	0.0053054	0.0006099	0.0001004	0.0000893	0.0797721	0.0001533
	Total	1.0000000	0.7804042	0.0759681	0.0575973	0.0053054	0.0006099	0.0001004	0.0000893	0.0797721	0.0001533
TOTOXEXP	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.4740167	0.3241911	0.0074455	0.0603263	0.0625544	0.0173430	0.0000000	0.0005893	0.0013093	0.0002577
	DISTSEC	0.2645057	0.2039666	0.0060676	0.0286634	0.0228160	0.0000000	0.0000000	0.0003113	0.0022903	0.0003903
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.2614776	0.1231219	0.0311179	0.0240702	0.0157122	0.0097299	0.0025105	0.0000366	0.0484500	0.0067285
	Total	1.0000000	0.6512797	0.0446310	0.1130599	0.1010826	0.0270729	0.0025105	0.0009372	0.0520496	0.0073766
TOTUGLINES	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.6250000	0.4227329	0.0094256	0.0805643	0.0849528	0.0248472	0.0000000	0.0007806	0.0014072	0.0002894
	DISTSEC	0.3750000	0.2891715	0.0086023	0.0406372	0.0323471	0.0000000	0.0000000	0.0004414	0.0032471	0.0005534
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.7119044	0.0180279	0.1212015	0.1173000	0.0248472	0.0000000	0.0012220	0.0046542	0.0008428

KENTUCKY POWER COMPANY
12 CP CLASS COST OF SERVICE STUDY
12 MONTHS ENDED JUNE 30, 2005

ALLOCATION METHOD	FUNCTIONAL FACTOR	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP TOD	MW	OL	SL
TRANS_TOTAL	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.6100000	0.2658107	0.0057248	0.0547844	0.0710268	0.0727475	0.1389013	0.0005070	0.0004025	0.0000952
	SUBTRAN	0.3900000	0.1592653	0.0033904	0.0341498	0.0453324	0.0518017	0.0957522	0.0003082	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.4250760	0.0091152	0.0889342	0.1163592	0.1245492	0.2346535	0.0008152	0.0004025	0.0000952

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY

CASE NO. 2005-00341

DIRECT TESTIMONY

OF
JAMES E. HENDERSON

ON BEHALF OF
KENTUCKY POWER COMPANY

September 26, 2005

DIRECT TESTIMONY OF
JAMES E. HENDERSON ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

Introduction

Q. Please state your name, business address and position.

A. My name is James E. Henderson. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. My position is Senior Staff Accountant in the Accounting Policy and Research Section of American Electric Power Service Corporation (AEPSC).

Q. What are your principal areas of responsibility?

A. I am responsible for depreciation studies and coordination of plant accounting policy for the AEP System companies.

Background

Q. Please summarize your educational background and work experience.

A. I received a Bachelor of Science Degree with a major in accounting from Columbus Business University in 1969. I am a licensed Public Accountant in the State of Ohio. I have attended three one-week sessions in depreciation life analysis sponsored by Western Michigan University Center of Depreciation Studies. I have been a member of the Depreciation Accounting Committee, which was merged into the Property Accounting and Valuation Committee of Edison Electrical Institute since 1976. I am a member of the Institute of Management Accountants and Senior Member of the Society of Depreciation Professionals.

I joined Columbus Southern Power Company (CSP), one of the AEP operating companies, as a part-time student employee in 1967. Upon graduation, I was employed full time and held various positions in the Accounting Department in the areas of plant accounting, tax accounting and depreciation. From 1978 to 1980, I held the position of Director of Depreciation Accounting and from 1980 to 1982, I held the position of Director of Plant Accounting and Depreciation. My responsibilities in those positions included performing depreciation studies, preparing book and federal income tax depreciation accruals, preparing and analyzing property valuations for state and local property tax assessments and supervising the accounting for CSP's investment in electric utility plant.

In August 1982, I transferred from CSP to the Rate Department of American Electric Power Service Corporation (AEPSC) as Manager of Depreciation Studies. In 1988, I transferred to the Accounting Department and retained the responsibilities for depreciation studies for the AEP operating companies.

Q. Have you previously filed testimony in regulatory proceedings?

A. Yes. I have filed testimony regarding depreciation rates with the Public Service Commissions in the states of Kentucky, Ohio, Oklahoma, Texas, Virginia and West Virginia. I was an industry panelist before the Federal Energy Regulatory Commission (FERC) (FERC Docket 02-0700) testifying on the implementation of Statement of Financial Standards No. 143, Accounting For Asset Retirement Obligations (SFAS 143).

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to recommend that the Kentucky Public Service Commission (Commission) authorize Kentucky Power Company (Kentucky Power or Company) to implement revised depreciation accrual rates for Kentucky Power Company's electric plant in service based on a depreciation study for Kentucky Power's electric utility plant in service at December 31, 2004 and to include the effects of the revised depreciation in determining depreciation expense in cost of service. Exhibit No. JEH-1 is a report of the results of the study. The depreciation rates determined by my study are intended to provide recovery of invested capital and cost of removal, and credit for salvage over the expected life of the property.

Q. Was this depreciation study prepared by you or under your supervision?

A. Yes.

Q. What was the purpose of the depreciation study?

A. The last depreciation study for Kentucky Power was performed in 1990. In the Commission's Order in Kentucky Power's Case No. 2002-00169, Kentucky Power was instructed to file a depreciation study within 3 years of the date of the Order or by the filing of its next general rate case, whichever occurs first. This study complies with that Order. The purpose of the present study is to recommend appropriate annual depreciation rates for Kentucky Power to use in computing annual book depreciation expense in light of current conditions.

Q. What were the results of your depreciation study?

A. Based on the results of the study, I am recommending an increase in annual depreciation expense of $3,656,922 or 0.28% in the annual accrual rate. The depreciation rate changes are necessary because of changes (both increases and decreases) in the average service lives and the gross salvage and cost of removal estimates that were used to calculate Kentucky Power's current depreciation rates.

Q. How do the depreciation rates and annual accruals as a result of your study compare with Kentucky Power's current rates and accruals?

A. A comparison of Kentucky Power's current rates and the study rates are shown below based on December 31, 2004 depreciable plant balances:

Composite Rates and Accruals

	Existing		Study	
Functional Plant Group	Rates	Accruals	Rates	Accruals
Steam Production Plant	3.90%	$17,713,144	3.57%	$16,215,226
Transmission Plant	1.71%	6,551,727	2.71%	10,398,016
Distribution Plant	3.52%	15,393,620	3.64%	15,907,812
General Plant	2.54%	728,364	5.31%	1,522,723
Total	3.10%	$40,386,855	3.38%	$44,043,777

The above summary is taken from Columns 4 through 7 of Schedule II of Exhibit JEH-1.

Q. Please explain the definition of depreciation as used in preparing your study.

A. The definition of depreciation that I used in preparing the study is the same that is used by the FERC and the National Association of Regulatory Utility

Commissioners. That definition is:

Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.

Service value means the difference between original cost and the net salvage value (net salvage value means the salvage value of the property retired less the cost of removal) of the electric plant.

Q. Please briefly describe the methods and procedures used in the study.

A. The methods and procedures are fully described on pages 1 through 9 of Exhibit JEH-1. In summary, all of the property included in this report was considered on a group plan. The group plan has been an integral part of depreciation accounting of regulated industries for many years. Under this plan, no attempt is made to keep track of the thousands of individual items making up a system. Under the group plan, depreciation is accrued upon the basis of the original cost of all property included in each depreciable plant group. Upon retirement of any depreciable property, its full cost, less any net salvage realized, is charged to the accumulated provision for depreciation regardless of the age of the particular item retired. Also under this plan, the dollars in each primary plant account are considered as a separate group for depreciation accounting purposes and an annual depreciation rate for each account is determined. In this study, the plant groups consisted of the individual primary plant accounts for Production, Transmission, Distribution and General Plant property. The depreciation rates were calculated by the Average Remaining Life Method which is the same method that was used to calculate Kentucky Power's current depreciation rates. The Remaining Life method recovers the original cost of the plant, adjusted for net salvage, less accumulated depreciation over the average remaining life of the plant.

For Production Plant, the generating unit retirement dates and the interim retirement history for the individual plant accounts were used to determine the average service lives and the remaining lives of the plants. The average service lives for the Company's Transmission, Distribution and General Plant were determined using statistical procedures similar to those used in the insurance industry in studies of human mortality. The historical retirement experience of the property groups were studied and the retirement characteristics of the property were described using the Iowa-type retirement dispersion curves.

The net salvage for each property group was determined based on actual historical experience for the Production, Transmission, Distribution and General Plant accounts. In addition, for Production Plant, Kentucky Power had a conceptual demolition cost estimate made by Brandenburg Industrial Service Company (Brandenburg). Brandenburg estimated the probable cost to demolish Big Sandy Plant based on the current price levels. My recommended depreciation rates for Production Plant included the probable demolition cost for Big Sandy Plant at current price levels. I recommend that Kentucky Power continue to update the demolition cost estimates for Big Sandy Plant in future depreciation studies to reflect future changes in price levels. This will enable the Company to recover the estimated actual removal costs that can reasonably be expected to be incurred at the time Big Sandy Plant is retired.

Q. Do you have any other recommendations regarding the adoption of your recommended depreciation rates?

A. Yes. I recommend that the Commission authorize Kentucky Power to adopt and apply the recommended depreciation accrual rates at the primary plant account level and that the accumulated depreciation be established by primary plant account as of a specific date, (e.g. the date the revised rates become effective) and from that date forward Kentucky Power should apply depreciation rates and maintain the accumulated depreciation at the primary plant account level.

Q. Please explain why you are recommending that Kentucky Power apply depreciation rates and maintain the accumulated depreciation at the primary plant account level.

A. Kentucky Power currently applies depreciation rates and maintains the accumulated depreciation at a functional plant level (i.e. Production, Transmission, Distribution and General). The amount of the accumulated depreciation is an important component in calculating remaining life depreciation rates Thus, the amount of accumulated depreciation has a direct effect on developing a depreciation rate for each plant account. If the accumulated depreciation is not maintained at the primary account level, it is necessary to allocate the functional plant accumulated depreciation to individual plant accounts based on what the calculated accumulated depreciation would be based on the survivor curves, average service lives, gross removal and gross salvage determined in the current depreciation study.

When the accumulated depreciation is maintained by primary plant account, it enables the Company to monitor depreciation accruals and removal/salvage costs actually recorded in each primary plant account and eliminate the requirement to allocate the accumulated depreciation to primary plant accounts. This will facilitate the identification of changes that occur in the primary plant account activity that lead to the recommendation of revised depreciation rates.

Q. Does your recommendation that the Company maintain the accumulated depreciation by primary account have any effect on the determination of the depreciation rates that you recommended as a result of this depreciation study?

A. No, it does not. My recommendation affects how the Company should be maintaining its accumulated depreciation in the future.

Q. Please describe SFAS 143.

A. The Financial Accounting Standards Board (FASB) issued SFAS 143 in June 2002. SFAS 143 prescribes the accounting for Asset Retirement Obligations (ARO) and was implemented by Kentucky Power effective January 1, 2003 as required by the FASB. SFAS 143 applies to legal obligations associated with the retirement of tangible, long-lived assets and requires that those legal obligations be recognized at fair value at the time the legal obligation was incurred if a reasonable estimate of fair value can be made. SFAS 143 defines a legal obligation as an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel.

Q. Has Kentucky Power recognized any ARO'S Under SFAS 143?

A. As stated in Kentucky Power's financial statements, the Company has identified, but not yet recognized, asset retirement obligation liabilities related to electric transmission and distribution as a result of the nature of certain easements on rights-of-way on which the Company has assets. Generally, these easements are perpetual and require only the retirement and removal of transmission and distribution assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements as the Company plans to use the facilities indefinitely.

Q. Does SFAS 143 change the accounting requirements for obligations that are not specific legal obligations for rate regulated companies such as Kentucky Power?

A. No it does not. Rate regulated companies such as Kentucky Power can continue to collect asset retirement costs (removal costs) that are not within the scope of SFAS 143 through depreciation rates when authorized by a ratemaking such as the Public Service Commission of Kentucky. However, for United States Security and Exchange Commission (SEC) financial reporting purposes, the amounts of removal coats that have been collected though the Company's Commission approved depreciation rates, and included in accumulated depreciation, must be reclassified to a regulatory liability. Kentucky Power has followed this accounting for SEC financial reporting purposes.

Q. Has the FERC issued any accounting instructions for ARO's?

A. Yes. On April 9, 2003 FERC issued Order 631. Order 631 added new balance sheet and income statement accounts to be utilized for recording ARO's. In addition, Order 631 revised definitions and, the general and plant accounting instructions contained in the Uniform System of Accounts.

Q. Did Order 631 address the accounting for cost of removal that does not constitute a legal obligation?

A. Yes. The FERC specifically addressed accounting for cost of removal that does not constitute a legal obligation in Section III, paragraph 36 of Order 631 as follows:

> As proposed in the NOPR, the rule applies to legal obligations associated with the retirement of tangible long-lived assets. Under the existing requirements of the Uniform System of Accounts removal costs that are not asset retirement obligations are included as a component of the depreciation expense and recorded in accumulated depreciation. The Commission notes that certain jurisdictional entities may have been receiving specific allowances for cost of removal for non-legal retirement obligations as a specific component in their rates approved by their regulators. The Commission did not propose any changes to its existing accounting requirements for cost of removal for

non-legal retirement obligations. Accordingly, jurisdictional entities are accounting for such costs consistent with the requirements of the Uniform System of Account under part 101 for public utilities and licensees, part 201 for natural gas companies and Part 352 for oil pipeline companies.

Q. Does your depreciation study comply with the accounting requirements of SFAS 143 and FERC Order 631?

A. Yes, it does. In my study I split the amounts of net salvage that I recommended into a gross removal component and a gross salvage component. Thus, for SEC financial reporting purposes, the amount of removal costs included in depreciation rates and accruals can readily be determined and reclassified to a regulatory liability account.

Q. Please explain the results of your study for Production Plant.

A. The composite rate for Steam Production Plant decreased from 3.90% to 3.57%. The decrease was principally caused by an increase in the total life span of Big Sandy Generating Plant Unit 2 and a decrease in the amount of negative net salvage for the generating station.

Q. Please explain the results of your study for Transmission Plant.

A. The composite rate for Transmission Plant increased from 1.71% to 2.71%. The increase was principally caused by a reduction of the average service lives for Accounts 353, Station Equipment and 355, Poles & Fixtures as indicated in the life analysis for those accounts and by increases in the net removal costs for this functional group of plant investment based on the actual cost of removal experienced during the period 1990 through 2004

Q. Please explain the results of your study for Distribution Plant.

A. The composite rate for Distribution Plant increased from 3.52% to 3.64%. The increase was principally caused by increases in net removal costs for this functional group of plant investments based on the actual cost of removal experienced during the period 1990 through 2004 offset, in part, by increases in the average service lives for nine of the twelve individual plant accounts that comprise this functional plant investment.

Q. Please explain the results of your study for General Plant.

A. The composite rate for General Plant increased from 2.54% to 5.31%. The increase is mainly attributable to the decrease in average service life for Accounts 390, Structures and Improvements and 397, Communication Equipment, and 398 Miscellaneous Equipment offset by both the increase in average service lives for Accounts 394, Tools, Shop and Garage Equipment and 395, Laboratory Equipment and an increase in positive net salvage for this functional plant investment.

Q. Does this complete your direct testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

STATE OF OHIO

CASE NO. 2005-00341

COUNTY OF FRANKLIN

AFFIDAVIT

James E. Henderson, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

James E. Henderson

WITNESS NAME

Subscribed and sworn to before me by WITNESS NAME this 19th day of Sept, 2005.

Catherine Hurston

Notary Public

NOTARIAL SEAL STATE OF OHIO

CATHERINE HURSTON
Notary Public, State of Ohio
My Commission Expires 11 15 2009

My Commission Expires ____________

EXHIBIT JEH-1

KENTUCKY POWER COMPANY

DEPRECIATION STUDY REPORT

OF

ELECTRIC PLANT IN SERVICE

AT DECEMBER 31, 2004

CONTENTS

INTRODUCTION

This report presents the results of a depreciation study of Kentucky Power Company's (KPCo) depreciable electric utility plant in service at December 31, 2004. The study was prepared by James E. Henderson, Senior Staff Accountant at American Electric Power Service Corporation (AEPSC). The purpose of this depreciation study was to develop appropriate annual depreciation accrual rates for each of the primary plant accounts, which comprise the functional groups for which KPCo computes its annual depreciation expense.

The recommended depreciation rates are based on the Average Remaining Life Method of computing depreciation. Further explanation of this method is contained in Section II of this report.

The definition of depreciation used in this Study is the same as that used by the Federal Energy Regulatory Commission (FERC) and the National Association of Regulatory Utility Commissioners:

> "Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities."

"Service value means the difference between original cost and the net salvage value (net salvage value means the salvage value of the property retired less the cost of removal) of the electric plant." (FERC Accounting and Reporting Requirements for Public Utilities and Licensees, ¶15.001.)

Section I of this report contains Schedule I, which shows the recommended depreciation accrual rates by primary plant accounts and composited to functional plant classifications; Schedule II, which shows a comparison of KPCo's current depreciation rates and accruals to the recommended rates and accruals and Schedule III that shows a comparison of the current mortality characteristics that were used to compute the recommended depreciation rates and the mortality characteristics used to determine the existing depreciation rates and accruals. A comparison of KPCo's current functional group composite depreciation rates and accruals to the recommended functional group rates and accruals follows:

Annual Rates and Accruals

	Current		Recommended		Increase
Functional Group	Rate %	Amount	Rate %	Amount	(Decrease)
Steam Production	3.90	$17,713,144(a)	3.57	$16,215,226	$(1,497,918)
Transmission Plant	1.71	6,551,727	2.71	10,398,016	3,846,289
Distribution Plant	3.52	15,393,620	3.64	15,907,812	514,192
General Plant	2.54	728,364	5.31	1,522,723	794,359
Total	3.10	$40,386,855	3.38	$44,043,777	$ 3,656,922

(a) The current approved depreciation rate for Steam Production Plant is 3.78%. The 3.78% rate does not include the approved amortization of SCR Catalysts. For comparison purposes, the amounts shown above under Current Rates and Accruals have been adjusted to include an annual amortization of $552,380 relating to the catalysts. The recommended depreciation rates and accruals shown above reflect the catalysts in the recommended depreciation rate of 3.57%.

Based on Depreciable Plant In Service as of December 31, 2004, I am recommending an increase in annual depreciation expense of $3,656,922 or 0.28% in the annual composite rate. The depreciation rate changes are necessary because of changes (both increases and decreases) in the average service lives and the gross salvage of removal estimates that were used to calculate KPCo's current depreciation rates.

KPCo currently applies depreciation rates and maintains the accumulated depreciation by functional plant classification. I recommend that KPCo adopt and apply the depreciation accrual rates at the primary plant account level and that the accumulated depreciation be established by primary plant account as of a specific date, (e.g. the date revised depreciation rates become effective) and from that date forward KPCo should apply depreciation rates and maintain the accumulated depreciation at the primary plant account level. This will facilitate monitoring the depreciation accruals and actual salvage and removal cost activity for future depreciation study purposes. This will also eliminate the requirement to allocate the accumulated depreciation to primary plant accounts in future depreciation studies.

Section II of this report contains an explanation of the methods and procedures used in this study. Examples of computations discussed in Section II appear in Appendix A.

SECTION I

SCHEDULES

SCHEDULES

SCHEDULE	SUBJECT
I	Determination of Recommended Annual Depreciation Rates and Accruals by Primary Plant Account
II	Comparison of Existing Annual Accrual Rates and Accruals To the Recommended Annual Accrual Rates and Accruals
III	Comparison of Property Mortality Characteristics

SCHEDULE I

Schedule I shows the determination of the recommended annual depreciation accrual rate by primary plant accounts by the straight line remaining life method. An explanation of the schedule follows:

Column I	-	Account number.
Column II	-	Account title.
Column III	-	Original Cost at December 31, 2004
Column IV	-	Average Life and (Iowa) Curve Type.
Column V	-	Terminal Retirement Date for accounts utilizing Life-Span Forecast
Column VI	-	Net Salvage Ratio.
Column VII	-	Total to be Recovered (Column III) * (Column IV).
Column VIII	-	Calculated Depreciation Requirement.
Column IX	-	Allocated Accumulated Depreciation – KPCo's Accounting group accumulated depreciation (book reserve) spread to each account on the basis of the Calculated Depreciation Requirement shown in Column VIII.
Column X	-	Remaining to be Recovered (Column VII - Column IX).
Column XI	-	Average Remaining Life.
Column XII	-	Recommended Annual Accrual Amount.
Column XIII	-	Recommend Annual Accrual Percent or Depreciation Rate (Column XII/Column III).

KENTUCKY POWER COMPANY
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINING LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2004
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

SCHEDULE I

ACCOUNT NO. (I)	ACCOUNT TITLE (II)	ORIGINAL COST AT 12/31/04 (III)	AVERAGE LIFE AND CURVE TYPE (IV)	TERMINAL RETIREMENT DATE (V)	NET SALVAGE RATIO (VI)	TOTAL TO BE RECOVERED (VII)	CALCULATED DEPRECIATION REQUIREMENT (VIII)	ALLOCATED ACCUMULATED DEPRECIATION (IX)	REMAINING TO BE RECOVERED (X)	AVERAGE REMAINING LIFE (XI)	RECOMMENDED ANNUAL AMOUNT (XII)	RECOMMENDED ACCRUAL PERCENT (XIII)
	STEAM PRODUCTION PLANT											
	BIG SANDY PLANT			2015/2034								
311.0	Structures & Improvements	36,149,758	FCST.		1.08	39,041,739	19,558,366	17,003,960	22,037,779	25.98	848,259	2.35%
312.0	Boiler Plant Equipment	324,538,695	FCST.		1.19	386,201,047	120,063,125	105,248,658 (a)	280,952,389	22.10	12,712,778	3.92%
314.0	Turbogenerator Units	73,038,983	FCST.		1.16	84,725,220	40,553,738	35,257,246	49,467,974	22.71	2,178,246	2.98%
315.0	Accessory Electrical Equipment	13,742,601	FCST.		1.10	15,116,861	8,374,746	7,280,968	7,835,893	25.81	303,599	2.21%
316.0	Misc. Power Plant Equip.	6,518,954	FCST.		1.11	7,236,039	3,408,827	2,963,620	4,272,419	24.79	172,344	2.64%
	Total Steam Production Plant	453,988,991				532,320,906	191,958,802	167,754,452	364,566,454		16,215,226	3.57%
	TRANSMISSION PLANT											
350.1	Land Rights	23,258,047	75 R4.0	N.A.	1.00	23,258,047	6,496,508	5,181,575	18,076,472	54.05	334,440	1.44%
352.0	Structures & Improvements	6,387,065	55 S3.0	N.A.	1.00	6,387,065	2,174,176	1,734,110	4,652,955	36.28	128,251	2.01%
353.0	Station Equipment	123,153,116	40 R1.5	N.A.	1.00	123,153,116	30,208,886	24,094,424	99,058,692	30.19	3,281,176	2.66%
354.0	Towers & Fixtures	92,364,356	55 R4.0	N.A.	1.35	124,691,881	44,490,496	35,485,349	89,206,532	35.38	2,521,383	2.73%
355.0	Poles & Fixtures	37,506,208	35 S6.0	N.A.	1.50	56,259,312	18,200,686	14,516,677	41,742,635	23.68	1,762,780	4.70%
356.0	OH Conductor & Devices	100,355,481	50 S6.0	N.A.	1.05	105,373,255	39,881,156	31,808,967	73,564,288	31.08	2,366,933	2.36%
356.0	Underground Conduit	11,590	37 R2.0	N.A.	1.00	11,590	5,713	4,557	7,033	18.76	375	3.23%
358.0	Underground Conductor	106,066	44 R1.0	N.A.	1.00	106,066	37,616	30,002	76,064	28.40	2,678	2.53%
	Total Transmission Plant	383,141,929				439,240,332	141,495,137	112,855,660	326,384,672		10,398,016	2.71%
	DISTRIBUTION PLANT											
360.1	Land Rights	3,691,802	75 R4.0	N.A.	1.00	3,691,802	1,464,290	1,521,740	2,170,062	45.25	47,957	1.30%
361.0	Structures & Improvements	4,231,065	70 L1.5	N.A.	1.00	4,231,065	801,496	832,942	3,398,123	56.74	59,889	1.42%
362.0	Station Equipment	42,017,840	30 R0.5	N.A.	1.00	42,017,840	11,888,208	12,354,632	29,663,208	21.51	1,379,043	3.28%
364.0	Poles, Towers, & Fixtures	124,672,243	28 R0.5	N.A.	1.40	174,541,140	48,873,736	50,791,264	123,749,876	20.16	6,138,387	4.92%
365.0	Overhead Conductor & Devices	99,426,561	30 R0.5	N.A.	0.80	79,541,249	19,903,904	20,684,820	58,856,429	22.49	2,617,004	2.63%
366.0	Underground Conduit	2,959,899	50 R1.0	N.A.	1.00	2,959,899	483,560	502,532	2,457,367	41.83	58,747	1.98%
367.0	Underground Conductor	5,482,068	53 R0.5	N.A.	0.85	4,659,758	603,991	627,688	4,032,070	46.13	87,407	1.59%
368.0	Line Transformers	84,185,422	29 R0.5	N.A.	0.75	63,139,067	18,278,290	18,995,426	44,143,640	20.60	2,142,895	2.55%
369.0	Services	31,239,944	22 R0.5	N.A.	0.85	26,553,952	6,927,939	7,199,752	19,354,200	16.26	1,190,295	3.81%
370.0	Meters	21,071,793	20 R3.0	N.A.	0.75	15,803,845	7,761,512	8,066,030	7,737,815	10.18	760,100	3.61%
371.0	Installations on Custs. Prem.	15,598,882	12 L0.0	N.A.	1.00	15,598,882	3,614,093	3,755,890	11,842,992	9.22	1,284,489	8.23%
373.0	Street Lighting & Signal Sys.	2,741,234	20 L0.0	N.A.	1.05	2,878,296	844,368	877,496	2,000,799	14.13	141,599	5.17%
	Total Distribution Plant	437,318,753				435,616,794	121,445,385	126,210,213	309,406,581		15,907,812	3.64%
	GENERAL PLANT											
389.2	Land Rights	84,011	75 R4.0	N.A.	1.00	84,011	10,301	5,029	78,982	65.80	1,200	1.43%
390.0	Structures & Improvements	19,295,997	25 L2.0	N.A.	0.90	17,366,397	8,266,103	4,035,838	13,330,560	13.10	1,017,600	5.27%
391.0	Office Furniture & Equipment	1,737,579	35 R0.5	N.A.	1.00	1,737,579	386,452	188,681	1,548,898	27.22	56,903	3.27%
392.0	Transportation Equipment	5,819	30 R3.0	N.A.	1.00	5,819	3,136	1,531	4,288	13.83	310	5.33%
393.0	Stores Equipment	189,262	30 L0.0	N.A.	1.00	189,262	47,037	22,965	166,297	22.54	7,378	3.90%
394.0	Tools Shop & Garage Equipment	1,711,318	32 L0.0	N.A.	1.00	1,711,318	262,618	128,220	1,583,098	27.09	58,438	3.41%
395.0	Laboratory Equipment	394,394	32 S5.0	N.A.	1.00	394,394	258,983	126,446	267,948	10.99	24,381	6.18%
396.0	Power Operated Equipment	5,931	8 SQ	N.A.	1.00	5,931	1,853	905	5,026	5.50	914	15.41%
397.0	Communication Equipment	4,666,769	19 S6.0	N.A.	0.90	4,200,092	1,960,549	957,217	3,242,875	10.13	320,126	6.86%
398.0	Miscellaneous Equipment	584,684	19 L2.0	N.A.	1.00	584,684	134,604	65,719	518,965	14.63	35,473	6.07%
	Total General Plant	28,675,764				26,279,487	11,331,636	5,532,552	20,746,935		1,522,723	5.31%
	Total Depreciable Plant	1,303,125,437				1,433,457,519	466,230,960	412,352,877 (a)	1,021,104,642		44,043,777	3.38%

(a) Includes allocated reserve of $105,161,967 plus $866,291 of accumulated amortization applicable to SCR Catalysts.

KENTUCKY POWER COMPANY
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINING LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2004

SCHEDULE II

ACCOUNT NO. (1)	ACCOUNT TITLE (2)	ORIGINAL COST AT 12/31/04 (3)	CURRENT RATE (4)	CURRENT ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
PRODUCTION PLANT							
	Steam Production						
	Big Sandy Plant						
311	Structures & Improvements	36,149,758	3.78%	1,366,461	2.35%	848,259	(518,202)
312	Boiler Plant Equipment	324,538,694	3.95%	12,819,923 (a)	3.92%	12,712,778	(107,145)
314	Turbogenerator Units	73,038,983	3.78%	2,760,874	2.98%	2,178,246	(582,628)
315	Accessory Electrical Equipment	13,742,601	3.78%	519,470	2.21%	303,599	(215,871)
316	Misc. Power Plant Equipment	6,518,954	3.78%	246,416	2.64%	172,344	(74,072)
	Total Steam Production	453,988,990	3.90%	17,713,144	3.57%	16,215,226	(1,497,918)
TRANSMISSION PLANT							
350.1	Rights of Way	23,258,047	1.71%	397,713	1.44%	334,440	(63,273)
352.0	Structures & Improvements	6,387,065	1.71%	109,219	2.01%	128,251	19,032
353.0	Station Equipment	123,153,116	1.71%	2,105,918	2.66%	3,281,176	1,175,258
354.0	Towers & Fixtures	92,364,356	1.71%	1,579,430	2.73%	2,521,383	941,953
355.0	Poles & Fixtures	37,506,208	1.71%	641,356	4.70%	1,762,780	1,121,424
356.0	OH Cond. & Devices	100,355,481	1.71%	1,716,079	2.36%	2,366,933	650,854
357.0	Underground Conduit	11,590	1.71%	198	3.24%	375	177
358.0	Underground Conductor	106,066	1.71%	1,814	2.52%	2,678	864
	Total Transmission Plant	383,141,929	1.71%	6,551,727	2.71%	10,398,016	3,846,289
DISTRIBUTION PLANT							
360.1	Rights of Way	3,691,802	3.52%	129,951	1.30%	47,957	(81,994)
361.0	Structures & Improvements	4,231,065	3.52%	148,933	1.42%	59,889	(89,044)
362.0	Station Equipment	42,017,840	3.52%	1,479,028	3.28%	1,379,043	(99,985)
364.0	Poles, Towers, & Fixtures	124,672,243	3.52%	4,388,463	4.92%	6,138,387	1,749,924
365.0	Overhead Conductor & Devices	99,426,561	3.52%	3,499,815	2.63%	2,617,004	(882,811)
366.0	Underground Conduit	2,959,899	3.52%	104,188	1.98%	58,747	(45,441)
367.0	Underground Conductor	5,482,068	3.52%	192,969	1.59%	87,407	(105,562)
368.0	Line Transformers	84,185,422	3.52%	2,963,327	2.55%	2,142,895	(820,432)
369.0	Services	31,239,944	3.52%	1,099,646	3.81%	1,190,295	90,649
370.0	Meters	21,071,793	3.52%	741,727	3.61%	760,100	18,373
371.0	Installations on Custs. Prem.	15,598,882	3.52%	549,081	8.23%	1,284,489	735,408
373.0	Street Lighting & Signal Sys.	2,741,234	3.52%	96,491	5.17%	141,599	45,108
	Total Distribution Plant	437,318,753	3.52%	15,393,620	3.64%	15,907,812	514,192
GENERAL PLANT							
389.1	Land Rights	84,011	2.54%	2,134	1.43%	1,200	(934)
390.0	Structures & Improvements	19,295,997	2.54%	490,118	5.27%	1,017,600	527,482
391.0	Office Furniture & Equipment	1,737,579	2.54%	44,135	3.27%	56,903	12,768
392.0	Transportation Equipment	5,819	2.54%	148	5.33%	310	162
393.0	Stores Equipment	189,262	2.54%	4,807	3.90%	7,378	2,571
394.0	Tools Shop & Garage Equipment	1,711,318	2.54%	43,467	3.41%	58,438	14,971
395.0	Laboratory Equipment	394,394	2.54%	10,018	6.18%	24,381	14,363
396.0	Power Operated Equipment	5,931	2.54%	151	15.41%	914	763
397.0	Communication Equipment	4,666,769	2.54%	118,536	6.86%	320,126	201,590
398.0	Miscellaneous Equipment	584,684	2.54%	14,851	6.07%	35,473	20,622
	Total General Plant	28,675,764	2.54%	728,364	5.31%	1,522,723	794,359
	Total Depreciable Plant	1,303,125,436	3.10%	40,386,855 (a)	3.38%	44,043,777	3,656,922

(a) Includes $552,360 of amortization related to SCR Catalysts

KENTUCKY POWER COMPANY
COMPARISON OF MORTALITY CHARACTERISTICS

SCHEDULE III

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Existing Rates			Study Rates				
		Average Service Life (Years)	Iowa Curve	Net Salvage Factor	Average Service Life (Years)	Iowa Curve	Salvage Factor	Cost of Removal Factor	Net Salvage Factor
TRANSMISSION PLANT									
350.1	Rights of Way	75	R4.0	0%	75	R4.0	0%	0%	0%
352.0	Structures & Improvements	55	S1.5	0%	55	S3.0	10%	10%	0%
353.0	Station Equipment	50	RO.5	25%	40	R1.5	35%	35%	0%
354.0	Towers & Fixtures	55	R4.0	0%	55	R4.0	0%	35%	-35%
355.0	Poles & Fixtures	45	R3.0	0%	35	S6.0	0%	50%	-50%
356.0	OH Cond. & Devices	50	R3.0	10%	50	S6.0	20%	25%	-5%
357.0	Underground Conduit	37	R2.0	0%	37	R2.0	0%	0%	0%
358.0	Underground Conductor and Devices	44	R1.0	0%	44	R1.0	0%	0%	0%
DISTRIBUTION PLANT									
360.1	Rights of Way	75	R4.0	0%	75	R4.0	0%	0%	0%
361.0	Structures & Improvements	65	LO.5	0%	70	L1.5	10%	10%	0%
362.0	Station Equipment	25	LO.O	25%	30	RO.5	35%	35%	0%
364.0	Poles, Towers, & Fixtures	28	LO.O	25%	28	RO.5	25%	65%	-40%
365.0	Overhead Conductor & Devices	26	R1.5	25%	30	R0.5	40%	20%	20%
366.0	Underground Conduit	37	R2.0	0%	50	R1.0	0%	0%	0%
367.0	Underground Conductor	44	R1.0	0%	53	RO.5	15%	0%	15%
368.0	Line Transformers	25	R1.5	15%	29	RO.5	40%	15%	25%
369.0	Services	18	R2.0	0%	22	RO.5	15%	0%	15%
370.0	Meters	27	R0.5	0%	20	R3.0	30%	5%	25%
371.0	Installations on Custs. Prem.	11	LO.O	30%	12	LO.O	30%	30%	0%
373.0	Street Lighting & Signal Sys.	15	LO.O	15%	20	LO.O	10%	15%	-5%
GENERAL PLANT									
389.2	Rights of Way	75	R4.0	0%	75	R4.0	0%	0%	0%
390.0	Structures & Improvements	45	L3.0	0%	25	L2.0	12%	2%	10%
391.0	Office Furniture & Equipment	35	R0.5	10%	35	RO.5	0%	0%	0%
392.0	Transportation Equipment	30	R3.0	0%	30	R3.0	0%	0%	0%
393.0	Stores Equipment	30	R1.0	0%	30	LO.O	0%	0%	0%
394.0	Tools Shop & Garage Equipment	30	RO.5	0%	32	LO.O	0%	0%	0%
395.0	Laboratory Equipment	30	L5.0	0%	32	S5.0	0%	0%	0%
396.0	Power Operated Equipment				8	SQ	0%	0%	0%
397.0	Communication Equipment	22	L3.0	0%	19	S6.0	10%	0%	10%
398.0	Miscellaneous Equipment	20	S5.0	0%	19	L2.0	0%	0%	0%

SECTION II

DISCUSSION OF METHODS AND PROCEDURES USED IN THE STUDY

SECTION II

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DISCUSSION OF METHODS AND PROCEDURES USED IN THE STUDY

1. Group Method

All of the depreciable property included in this report was considered on a group plan. Under the group plan, depreciation expense is accrued upon the basis of the original cost of all property included in each depreciable plant account. Upon retirement of any depreciable property, its full cost, less any net salvage realized, is charged to the accrued depreciation reserve regardless of the age of the particular item retired. Also, under this plan, the dollars in each primary plant account are considered as a separate group for depreciation accounting purposes and an annual depreciation rate for each account is determined. The annual accruals by primary account were then summed, to arrive at the total accrual for each functional group. The total accrual divided by the original cost yields the functional group accrual rate.

2. Determination of Annual Depreciation Rates

By the Average Remaining Life Method

KPCo's current depreciation rates are based on the Average Remaining Life Method. The Average Remaining Life Method recovers the original cost of the plant, adjusted for net salvage, less the accumulated depreciation, over the average remaining life of the plant. By this method, the annual depreciation rate for each account is determined on the following basis:

Annual
Depreciation Expense =

$$\frac{\text{(Orig. Cost) (Net Salvage Ratio) - Accumulated Depreciation}}{\text{Average Remaining Life}}$$

$$\text{Annual Depreciation Rate} = \frac{\text{Annual Depreciation Expense}}{\text{Original Cost}}$$

3. Methods of Life Analysis

Depending upon the type of property and the nature of the data available from the property accounting records, one of three life analyses was used to arrive at the historically realized mortality characteristics and service lives of the depreciable plant investments. These methods are identified and described as follows:

Forecast Analysis

The life span forecast analysis was employed for Production Plant. KPCo's investment in production is the Big Sandy Generating Station which consists of Unit One with a nameplate capacity of 260,000 KW and Unit Two with a nameplate capacity of 800,000 KW. Units One and Two were placed in service in 1963 and 1969 respectively. The life-span method of analysis is particularly suited to specific location property, such as Big Sandy, where all of the surviving investments are likely to be retired in total at a future date.

The key elements in the life span forecast analysis are the age of the surviving investments, the projected retirement date of the facility and the expected interim retirements. Interim retirements are those that are expected to occur between the date of the depreciation study and the expected final retirement date of the generating plant. Examples of interim retirements include fans, pumps, motors, a set of boiler tubes, a turbine rotor, etc. The interim retirement history for each primary production plant account was analyzed and the results of those analyses were used to project future interim retirements. An example of the interim retirement for Account 311, Structures and Improvements, is shown in the Appendix on Page A-1.

The age of the surviving investments were obtained from KPCo's property accounting records. American Electric Power Service Corporation provided the retirement dates used in the life-span analysis. The retirement dates for Big Sandy Plant are Unit 1 in 2015 and Unit 2 in 2034.

Actuarial Analysis

This method of analyzing past experience represents the application to industrial property of statistical procedures developed in the life insurance field for investigating human mortality. It is distinguished from other methods of life estimation by the requirement that it is necessary to know the age of the property at the time of its retirement and the age of survivors, or plant remaining in service; that is, the installation date must be known for each particular retirement and for each particular survivor.

The application of this method involves the statistical procedure known as the "annual rate method" of analysis. This procedure relates the retirements during each age interval to the exposures at the beginning of that interval, the ratio of these being the annual retirement ratio. Subtracting each retirement ratio from unity yields a sequence of annual survival ratios from which a survivor curve can be determined. This is accomplished by the consecutive multiplication of the survivor ratios. The length of this curve depends primarily upon the age of the oldest property. Normally, if the period of years from the inception of the account to the time of the study is short in relation to the expected maximum life of the property, an incomplete or stub survivor curve results.

While there are a number of acceptable methods of smoothing and extending this stub survivor curve in order to compute the area under it from which the average life is determined, the well-known Iowa Type Curve Method was used in this study.

By this procedure, instead of mathematically smoothing and projecting the stub survivor curve to determine the average life of the group, it was assumed that the stub curve would have the same mortality characteristics as the type curve selected. The selection of the appropriate type curve and average life is accomplished by plotting the stub curve, superimposing on it Iowa curves of the various types and average lives drawn to the same scale, and then determining which Iowa type curve and average life best matches the stub.

An example of the calculations involved in the Actuarial Method of Life Analysis is shown in the Appendix on Pages A-2 through A-4 for Account 362.0-Distribution Station Equipment. Pages A-2 AND A-3 show the computation of the actual survivor curve for the experience band 1965 - 2004, inclusive based on historical data supplied by KPCO. The actual survivor curve for the 1965- 2004 period is plotted and matched on Page A-4, as explained above. This method was used for the following accounts:

352.0 Transmission Structures & Improvements
353.0 Transmission Station Equipment
361.0 Distribution Structures & Improvements
362.0 Distribution Station Equipment

390.1 General Structures & Improvements

Simulated Plant Record Analysis

The "Simulated Plant Record" (SPR) method designates a class of statistical techniques that provide an estimate of the age distribution, mortality dispersion and average service life of property accounts whose recorded history provides no indication of the age of the property units when retired from service. For each such account, the available property records usually reveal only the annual gross additions, annual retirements and balances with no indication of the age of either plant retirements or annual plant balances. For this study, the "Balances method" of analysis was used.

The SPR Balances Method is a trial and error procedure that attempts to duplicate the annual balance of a plant account by distributing the actual annual gross additions over time according to an assumed mortality distribution. Specifically, the dollars remaining in service at any date are estimated by multiplying each year's additions by the successive proportion surviving at each age as given by the assumed survivor characteristics. For a given year, the balance indicated is the accumulation of survivors from all vintages and this is compared with the actual book balance. This process is repeated for a different survivor curves and average life combinations until a pattern is discovered which produces a series of "simulated balances" most nearly equaling the actual balances shown in a company's books.

This determination is based on the distribution producing the minimum sum of squared differences between the simulated balance and the actual balances over a test period of years.

The iterative nature of the simulated methods makes them ideally suited for computerized analysis. For each analysis of a given property account, the computer program provides a single page summary containing the results of each analysis indicating the "best fit" based on criteria selected by the user.

The results of such an analysis by the Balance Method is shown for Account 367 – Underground Conductor & Devices on page A-5 in the Appendix. In the case of the Balances Method each curve type tested is shown along with the average service life that produced the minimum sum of squared differences from the actual balances. The analysis also shows the value of the Index of Variation of the difference that is calculated according to the following equation for the Balances Method:

$$\text{Index of Variation} = (1000)\sqrt{\frac{\text{Sum of Squared Differences}}{\text{Number of Test Years}}} \bigg/ \text{Average Actual Balance}$$

The lower the value of the Index the better the agreement with the actual data.

The SPR Method of Life Analysis was utilized for the following accounts:

354.0 Transmission Towers & Fixtures
355.0 Transmission Poles & Fixtures
356.0 OH Conductor & Devices
364.0 Distribution Poles, Towers & Fixtures
365.0 Distribution OH Conductor & Devices
366.0 Underground Conduit
367.0 Underground Conductor & Devices
368.0 Distribution Line Transformers

369.0 Distribution Services

370.0 Distribution Meters

371.0 Installation on Customers Premises

373.0 Street Lighting & Signal Systems

391.0 Office Furniture & Equipment

392.0 Transportation Equipment

393.0 Stores Equipment

394.0 Tools, Shop and Garage Equipment

395.0 Laboratory Equipment

397.0 Communication Equipment

398.0 Miscellaneous Equipment

4. Final Selection of Average Life and Curve Type

The final selection of average life and curve type for each depreciable plant account analyzed by the Actuarial Method was primarily based on the results of the mortality analyses of past retirement history.

5. Net Salvage

The net salvage percentages used in this report are expressed as percent of original cost and are based primarily on the Company's experience combined with the experienced judgment of the analyst. KPCo maintains salvage and removal costs at the functional plant level, rather than by primary plant accounts. To aid in the selection of net salvage percentages, a review was made of the Company's experience for each plant function with respect to salvage and removal costs for the period 1954-2004. A sample of the type of salvage analysis made appears in Appendix A on Pages A-6 through A-11 for the Distribution Plant function. The salvage program analyzes historical experience on an annual basis, on the cumulative history basis and for 15 year moving averages to get the historical gross salvage, gross cost of removal and net salvage. In order to determine gross salvage, gross removal and net salvage percentages for the individual plant accounts, the original cost retirements were detailed by account for the period 1990 through 2004 and, based on judgment, gross salvage and cost of removal percentages were selected for each account. The salvage and removal percentages for each account were then netted to determine a net salvage percentage for each account.

The net salvage percents were converted to net salvage ratios and appear in Column VI on Schedule I and were used to determine the total amount to be recovered through depreciation. The same net salvage was also reflected in the determination of the calculated depreciation requirement, which was used to allocate the accumulated depreciation at the functional group to the accounts comprising each group.

The net salvage ratios shown in Column VI on Schedule I in Section I of this report may be explained as follows:

a. Where the ratio is shown as unity (1.00), it was assumed that the net salvage in that particular account would be zero.

b. Where the ratio is less than unity, it was assumed that the salvage exceeded the removal costs. For example, if the net salvage were 20%, the net salvage ratio would be expressed as .80.

c. Where the ratio is greater than unity, it was assumed that the salvage was less than the cost of removal. For example, if the net salvage were minus 5%, the net salvage ratio would be expressed as 1.05.

Net Salvage for Steam Production Plant

While the analysis described above was used to determine the net salvage applicable to interim retirements for steam production plant, the most significant net salvage realization for generating plants occurs at the end of their life. Therefore, to assist in establishing the net salvage applicable to KPCo's steam generating plant, KPCo had a conceptual demolition cost estimate prepared by Brandenburg Industrial Service Company for Big Sandy Plant. The cost estimate to demolish the plant is based on current (2004) price levels. The estimates of demolition costs were incorporated into the net salvage ratios for Steam Production Plant.

6. Effects of Statement of Financial Accounting Standards No. 143 (SFAS 143) and Federal Energy Regulatory Commission (FERC) Order 631 on Net Salvage

The Financial Accounting Standards Board (FASB) issued SFAS 143, Accounting for Asset Retirement Obligations, in June 2002. SFAS 143 became effective January 1, 2003 for companies whose fiscal year ends on December 31. SFAS 143 is a financial accounting requirement that deals with the identification, measurement and recording of legal liabilities associated with asset retirement. SFAS 143 was designed to standardize the way that different companies and different industries account for cost of removal when there is a legal asset retirement obligation. SFAS 143 was not intended to address the appropriate ratemaking treatment for regulated utilities.

As stated in KPCo's financial statements, KPCo has identified, but not recognized, asset retirement obligations related to electric transmission and distribution as a result of the nature of certain easements on property on which KPCo has assets. Generally these easements are perpetual and require only the retirement and removal of transmission and distribution assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements as KPCo plans to use the facilities indefinitely.

SFAS 143 did not directly change the accounting requirements for rate-regulated companies for removal costs that are not a legal retirement obligation. The Security and Exchange Commission (SEC) has interpreted SFAS 143 to require that cost of removal that is not a legal obligation should not be recognized under Generally Accepted Accounting Principles (GAAP) by unregulated entities. Statement of Financial Accounting Standards No. 71 (SFAS 71) provides that any such amounts that are recovered in rates by regulated enterprises would be classified as regulatory liabilities for SEC reporting purposes.

The (FERC) issued Order 631 on April 9, 2003. Order 631 added new balance sheet and income statement accounts to be used for recording legal Asset Retirement Obligations. In addition, Order 631 revised definitions and, the general and plant instructions contained in the FERC Uniform System of Accounts.

FERC also specifically addressed accounting for cost of removal that does not constitute a legal obligation in Section III, paragraph 36 of Order 631 as follows:

> As proposed in the NOPR, the rule applies to legal obligations associated with the retirement of tangible long-lived assets. Under existing requirements of the Uniform System of Accounts removal costs that are not asset retirement obligations are included as a component of the depreciation expense and recorded in accumulated depreciation. The Commission notes that certain jurisdictional entities may have been receiving specific allowances for cost of removal for non-legal retirement obligations as a specific component in their rates approved by their regulators. The Commission did not propose any changes to its existing

accounting requirements for cost of removal for non-legal retirement obligations. Accordingly, jurisdictional entities are accounting for such costs consistent with the requirements of the Uniform System of Accounts under Part 101 for public utilities and licensees, Part 201 for natural gas companies and Part 352 for oil pipeline companies.

KPCo's current book depreciation study rate recommendations comply with the accounting requirements of SFAS 143 and FERC Order 631. The study splits the amount of net salvage into a gross removal component and a gross salvage component. Thus, for SEC financial reporting purposes, the amount of removal costs included in depreciation rates and accruals can readily be determined and reclassified to a regulatory liability account.

7. Calculation of Depreciation Requirement at December 31, 2004

The accumulated depreciation by functional group was allocated to individual plant accounts based on the calculation of a depreciation requirement (theoretical reserve) for each plant account using the average service life, curve type and net salvage amount recommended in this study. An example of the calculation of the depreciation requirement at December 31, 2004, for Account 353 - Transmission Station Equipment, is shown on Pages A-12 and A-13 in Appendix A.

That sample printout is explained in detail as follows:

Column I - Age of each year's installation at December 31, 2004, based on the conventional procedure that all property installed in any year is assumed to be installed at the mid-point of that year.

Column II -	Year of installation of the surviving dollars shown in Column III.
Column III -	The original cost at December 31, 2004, by year installed, as supplied directly from Company records.
Column IV -	The Average Remaining Life of each vintage of Original Cost at the various ages indicated in Column I.
Column V -	Depreciation Reserve Ratio based on the Life and Dispersion (Iowa Curve) shown in Column IV heading.
Column VI -	Theoretical Reserve is the product of Column III times Column V for each year.

The effect of any estimated net salvage, as indicated on Page A-13, is provided by adjusting the subtotal rather than having each vintage of original cost appearing in Column III reflect such salvage.

The average Remaining Life, also shown, is the result of the weighing of the dollars of each age.

8. Study Results

The average service life, retirement dispersion pattern and net salvage pattern used to calculate each primary plant account rate are shown on Schedule 2. The mortality characteristics and net salvage values for the current rates are also shown. The changes to the mortality characteristics follow the trends shown by the historical retirement experience. The gross salvage and gross cost of removal percentages were largely based on the history of the account for the period 1990-2004.

Production Plant

The composite rate for Steam Production Plant decreased from 3.90% to 3.57%. The decrease was caused by an increase in the total life span of Unit 2 and a decrease in the amount of negative net salvage.

Transmission Plant

The composite rate for Transmission Plant increased from 1.71% to 2.71%. The increase was caused by a reduction of the average service lives for Accounts 353, Station Equipment and 355, Poles & Fixtures as indicated in the life analysis for those accounts and by increases in the net removal costs for this functional group of plant investment based on the actual cost of removal experienced during the period 1990 through 2004.

Distribution Plant

The composite rate for Distribution Plant increased from 3.52% to 3.64%. The increase was caused by increases in net removal costs for this functional group of plant investments based on the actual cost of removal experienced during the period 1990 through 2004 offset, in part, by increases in the average service lives for nine of the twelve individual plant accounts that comprise this functional plant investment.

General Plant

The composite rate for General Plant increased from 2.54% to 5.31%. The increase is mainly attributable to the decrease in average service life for Accounts 390, Structures and Improvements and 397, Communication Equipment, and 398 Miscellaneous Equipment offset by both the increase in average service lives for Accounts 394, Tools, Shop and Garage Equipment and 395, Laboratory Equipment and an increase in positive net salvage for this functional plant investment.

APPENDIX A

KENTUCKY POWER COMPANY
DEPRECIATION STUDY AS OF DECEMBER 31, 2004
CALCULATION OF AVERAGE REMAINING LIFE
BIG SANDY PLANT ACCOUNT 311
RETIREMENT YEARS - UNIT 1 2015; UNIT 2 2034

ANNUAL INTERIM RETIREMENT RATE 0.0011

YEAR	AMOUNT RETIRED	REM. LIFE (YEARS)	DOLLAR YEARS	AVERAGE REM. LIFE
2005	39,765	0.5	19,882	
2006	39,765	1.5	59,647	
2007	39,765	2.5	99,412	
2008	39,765	3.5	139,177	
2009	39,765	4.5	178,941	
2010	39,765	5.5	218,706	
2011	39,765	6.5	258,471	
2012	39,765	7.5	298,236	
2013	39,765	8.5	338,000	
2014	39,765	9.5	377,765	
2015	5,875,352	10.5	61,691,193	
2016	33,346	11.5	383,474	
2017	33,346	12.5	416,820	
2018	33,346	13.5	450,165	
2019	33,346	14.5	483,511	
2020	33,346	15.5	516,857	
2021	33,346	16.5	550,202	
2022	33,346	17.5	583,548	
2023	33,346	18.5	616,893	
2024	33,346	19.5	650,239	
2025	33,346	20.5	683,585	
2026	33,346	21.5	716,930	
2027	33,346	22.5	750,276	
2028	33,346	23.5	783,621	
2029	33,346	24.5	816,967	
2030	33,346	25.5	850,312	
2031	33,346	26.5	883,658	
2032	33,346	27.5	917,004	
2033	33,346	28.5	950,349	
2034	29,276,538	29.5	863,657,881	
TOTALS	36,149,758		939,341,723	25.98

INTERIM RETIREMENTS:

Total Plant at 12/31/04	36,149,758
Less Retirement of Unit 1 in 2015	-5,835,587
Less Final Retirement in year 2034	-29,276,538
Total Interim Retirements	1,037,633

EXHIBIT JEH-1

1965 THRU 2004 BAND ANALYSIS SURVIVOR REPORT

AGE	RETIREMENTS	EXPOSURES	ANNUAL % SURVIVORS	CUMULATIVE % SURVIVORS
0.50	0.	4259877.	100.00	100.00
1.50	1747.	4266164.	99.96	99.96
2.50	1155.	3873959.	99.97	99.93
3.50	3555.	3834556.	99.91	99.84
4.50	3444.	3826474.	99.91	99.75
5.50	1793.	3722568.	99.95	99.70
6.50	3880.	3328214.	99.88	99.58
7.50	17098.	3297438.	99.48	99.07
8.50	808.	3221102.	99.97	99.04
9.50	38290.	3192381.	98.80	97.85
10.50	1139.	2549912.	99.96	97.81
11.50	1676.	2449797.	99.93	97.74
12.50	1008.	2202706.	99.95	97.70
13.50	1550.	2098464.	99.93	97.63
14.50	1888.	1756879.	99.89	97.52
15.50	905.	1727003.	99.95	97.47
16.50	3305.	1698049.	99.81	97.28
17.50	9268.	1665550.	99.44	96.74
18.50	263.	1531080.	99.98	96.72
19.50	1537.	1375223.	99.89	96.61
20.50	140.	1255985.	99.99	96.60
21.50	2932.	1245757.	99.76	96.38
22.50	21508.	1237444.	98.26	94.70
23.50	158.	1111339.	99.99	94.69
24.50	13816.	1010540.	98.63	93.39
25.50	991.	625620.	99.84	93.24
26.50	308.	619952.	99.95	93.20
27.50	4456.	612367.	99.27	92.52
28.50	3407.	524459.	99.35	91.92
29.50	2600.	499206.	99.48	91.44
30.50	726.	423902.	99.83	91.28
31.50	2506.	360311.	99.30	90.65
32.50	1985.	313987.	99.37	90.08
33.50	2658.	262208.	98.99	89.16
34.50	2247.	200164.	98.88	88.16
35.50	787.	184660.	99.57	87.79

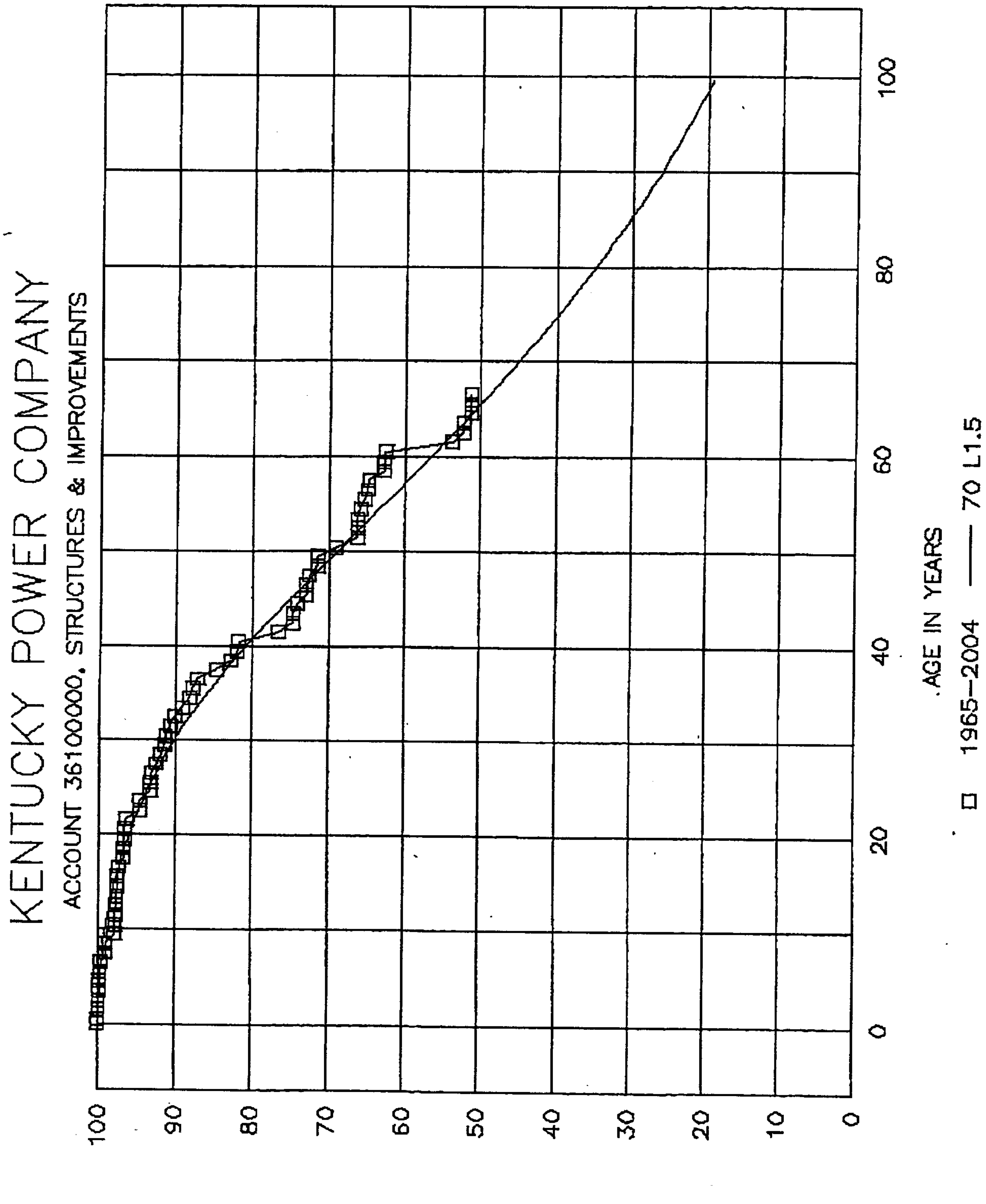
**** KENTUCKY POWER COMPANY ****
ACCOUNT NO.: 36100000

1965 THRU 2004 BAND ANALYSIS SURVIVOR REPORT

AGE	RETIREMENTS	EXPOSURES	% ANNUAL SURVIVORS	% CUMULATIVE SURVIVORS
36.50	1111.	178573.	99.38	87.24
37.50	4615.	158702.	97.09	84.70
38.50	3124.	141004.	97.78	82.83
39.50	1141.	106784.	98.93	81.94
40.50	200.	103624.	99.81	81.78
41.50	6881.	110503.	93.77	76.69
42.50	2638.	105379.	97.50	74.77
43.50	100.	102551.	99.90	74.70
44.50	746.	100866.	99.26	74.15
45.50	1679.	99829.	98.32	72.90
46.50	0.	98393.	100.00	72.90
47.50	449.	99271.	99.55	72.57
48.50	1362.	92466.	98.53	71.50
49.50	0.	85725.	100.00	71.50
50.50	2829.	84945.	96.67	69.12
51.50	3077.	77210.	96.01	66.36
52.50	0.	64818.	100.00	66.36
53.50	0.	60336.	100.00	66.36
54.50	370.	57470.	99.36	65.94
55.50	483.	53328.	99.09	65.34
56.50	261.	48983.	99.47	64.99
57.50	111.	43548.	99.75	64.83
58.50	1262.	40929.	96.92	62.83
59.50	0.	39625.	100.00	62.83
60.50	83.	38679.	99.79	62.69
61.50	5484.	38596.	85.79	53.78
62.50	852.	31440.	97.29	52.33
63.50	0.	29611.	100.00	52.33
64.50	540.	29471.	98.17	51.37
65.50	0.	25392.	100.00	51.37
66.50	0.	25392.	100.00	51.37

TOTAL 194932.

REALIZED LIFE = 55.53 YEARS



A 4

PERCENT SURVIVING

DELOITTE HASKINS & SELLS DEPRECIATION SYSTEM - DSSIMBAL02 RELEASE 5.0

STUDY AS OF DECEMBER 31, 2004

**** KENTUCKY POWER COMPANY **** 6-21-2005

SIMULATED PLANT BALANCE METHOD OF LIFE ANALYSIS FOR ACCOUNT 36700000

USING BALANCES PERIOD EQUAL TO LAST 40 YEARS

AVERAGE LIFE AT WHICH BOOK BALS EQUAL SIMULATED BALS AT END OF										MORT	INDEX OF VARIATION FOR ANALYSIS OF DATA ENDING IN									
1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	DISP	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
67.5	-66.8	65.9	65.4	65.3	65.2	65.5	65.3	65.4	65.5	SC	121	118	123	116	106	98	94	87	81	76
49.5	49.3	48.9	48.8	49.0	49.1	49.5	49.6	49.8	50.0	S-.5	105	98	98	91	86	81	-86	-80	79	78
37.4	37.6	37.6	37.7	38.1	38.3	38.7	39.0	39.2	39.6	S0	113	103	94	89	97	101	119	115	119	124
32.4	32.7	32.9	33.1	33.6	34.0	34.4	34.8	35.2	35.5	S0.5	135	127	116	114	128	135	156	153	159	164
28.8	29.1	29.3	29.6	29.9	30.2	30.6	30.8	31.2	31.7	S1	189	182	170	171	186	196	217	216	223	228
26.8	27.2	27.4	27.8	28.2	28.5	28.9	29.2	29.6	29.9	S1.5	232	226	214	216	232	242	262	262	269	275
24.8	25.3	25.6	26.1	26.5	26.9	27.4	27.7	28.1	28.5	S2	303	297	284	285	298	306	323	321	326	329
22.6	22.9	23.2	23.8	24.4	24.9	25.5	25.9	26.3	26.8	S3	415	420	416	412	419	420	429	421	421	418
21.5	21.9	22.2	22.6	23.0	23.5	24.1	24.6	25.1	25.5	S4	503	508	508	526	556	560	554	534	523	511
21.0	21.4	21.7	22.1	22.5	22.9	23.4	23.9	24.4	24.9	S5	558	565	570	595	626	645	650	614	592	572
20.7	21.1	21.5	21.9	22.3	22.7	23.1	23.6	24.1	24.6	S6	587	599	613	646	680	695	707	663	629	605
53.1	53.0	52.8	52.8	53.0	53.3	53.7	53.8	54.1	54.3	L0	103	95	92	85	-82	-79	90	84	84	85
43.9	44.1	44.0	44.2	44.6	44.9	45.4	45.7	46.1	46.4	L0.5	105	96	88	82	88	90	106	102	104	108
36.9	37.2	37.3	37.6	37.9	38.3	38.7	39.0	39.3	39.7	L1	135	126	114	111	122	128	147	144	149	153
32.1	32.5	32.8	33.1	33.6	34.1	34.6	35.0	35.4	35.8	L1.5	169	162	149	149	163	171	190	187	193	197
28.7	29.1	29.3	29.6	30.0	30.3	30.7	31.0	31.6	32.1	L2	234	228	216	218	234	244	265	265	268	269
24.7	25.2	25.6	26.1	26.5	27.0	27.4	27.8	28.2	28.5	L3	355	345	328	326	336	342	358	355	359	362
22.3	22.6	23.0	23.4	24.0	24.6	25.1	25.5	26.0	26.4	L4	462	472	473	476	471	464	467	456	454	451
21.4	21.8	22.1	22.5	22.9	23.3	23.9	24.4	24.9	25.4	L5	528	539	542	562	588	595	579	554	541	530
54.0	53.6	53.0	52.7	52.7	52.7	53.0	52.9	53.0	53.2	R0.5	116	111	115	108	99	91	90	83	-77	-73
42.4	42.2	41.8	41.6	41.8	42.0	42.4	42.5	42.7	43.0	R1	105	99	99	91	87	82	89	83	81	81
35.5	35.5	35.4	35.5	35.8	36.0	36.4	36.6	36.9	37.2	R1.5	-95	-87	-81	-76	84	87	105	102	106	111
29.6	29.8	29.9	30.1	30.4	30.6	30.9	31.2	31.7	32.1	R2	115	109	100	103	123	135	160	161	170	177
26.8	27.1	27.4	27.7	28.0	28.4	28.8	29.1	29.4	29.7	R2.5	168	167	159	166	188	202	226	227	236	245
24.0	24.6	25.0	25.4	25.9	26.4	26.9	27.2	27.6	28.0	R3	267	269	261	269	288	298	317	316	321	325
22.1	22.4	22.7	23.0	23.6	24.2	24.8	25.3	25.7	26.2	R4	410	420	426	452	469	467	472	458	453	446
21.2	21.5	21.9	22.2	22.6	23.0	23.6	24.1	24.6	25.1	R5	528	534	540	567	604	628	622	590	568	549

THE INDEX OF VARIATION IS MULTIPLIED BY 10 TO OBTAIN A HIGHER LEVEL OF RANKING PRECISION

EXHIBIT JEH-1

KENTUCKY POWER COMPANY 7-13-2005

ACCOUNT NO.: 10860000

DISTRIBUTION PLANT

			REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
YEAR	ADDITIONS	RETIREMENTS	AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1954	0.	345614.	0.	0.%	164293.	48.%	66201.	19.%	28.%	28.%
1955	0.	329795.	0.	0.%	163818.	50.%	68960.	21.%	29.%	29.%
1956	0.	340400.	0.	0.%	175639.	52.%	81844.	24.%	28.%	28.%
1957	0.	560530.	0.	0.%	243234.	43.%	141931.	25.%	18.%	18.%
1958	0.	505375.	0.	0.%	206808.	41.%	144792.	29.%	12.%	12.%
1959	0.	624939.	0.	0.%	259031.	41.%	152087.	24.%	17.%	17.%
1960	0.	492849.	0.	0.%	271181.	55.%	161636.	33.%	22.%	22.%
1961	0.	819969.	0.	0.%	381111.	46.%	170331.	21.%	26.%	26.%
1962	0.	558196.	0.	0.%	299388.	54.%	192682.	35.%	19.%	19.%
1963	0.	706977.	0.	0.%	279116.	39.%	194420.	28.%	12.%	12.%
1964	0.	773027.	0.	0.%	304668.	39.%	189822.	25.%	15.%	15.%
1965	0.	1012221.	0.	0.%	374123.	37.%	239135.	24.%	13.%	13.%
1966	0.	1071099.	0.	0.%	450349.	42.%	285103.	27.%	15.%	15.%
1967	0.	1463163.	0.	0.%	413889.	28.%	342901.	23.%	5.%	5.%
1968	0.	1330710.	0.	0.%	670448.	50.%	479783.	36.%	14.%	14.%
1969	0.	1560135.	0.	0.%	646533.	41.%	347617.	22.%	19.%	19.%
1970	0.	1143715.	0.	0.%	400222.	35.%	357897.	31.%	4.%	4.%
1971	0.	1315603.	0.	0.%	543957.	41.%	401721.	31.%	11.%	11.%
1972	0.	1475429.	0.	0.%	752589.	51.%	490837.	33.%	18.%	18.%
1973	0.	1773250.	0.	0.%	703812.	40.%	491738.	28.%	12.%	12.%
1974	0.	1273997.	0.	0.%	921165.	72.%	527796.	41.%	31.%	31.%
1975	0.	1413889.	0.	0.%	633350.	45.%	485488.	34.%	10.%	10.%
1976	0.	1770503.	0.	0.%	905056.	51.%	680443.	38.%	13.%	13.%
1977	0.	1790525.	0.	0.%	1032217.	58.%	928730.	52.%	6.%	6.%
1978	0.	2839810.	0.	0.%	1622814.	57.%	952797.	34.%	24.%	24.%
1979	0.	2379695.	0.	0.%	1368931.	58.%	1048294.	44.%	13.%	13.%
1980	0.	3067886.	0.	0.%	1455926.	47.%	1423814.	46.%	1.%	1.%
1981	0.	4492306.	0.	0.%	1883382.	42.%	1737241.	39.%	3.%	3.%
1982	0.	2552584.	0.	0.%	1586478.	62.%	1503023.	59.%	3.%	3.%
1983	0.	3917704.	0.	0.%	1560432.	40.%	1361570.	35.%	5.%	5.%
1984	0.	2274942.	0.	0.%	1275047.	56.%	1464480.	64.%	-8.%	-8.%
1985	0.	3390814.	0.	0.%	1033246.	30.%	1315547.	39.%	-8.%	-8.%
1986	0.	4122421.	0.	0.%	1703914.	41.%	1814294.	44.%	-3.%	-3.%
1987	0.	5062869.	0.	0.%	2341368.	46.%	1686747.	33.%	13.%	13.%
1988	0.	5092695.	0.	0.%	2009198.	39.%	1881879.	37.%	3.%	3.%
1989	0.	7285672.	0.	0.%	5727263.	79.%	1888999.	26.%	53.%	53.%
1990	0.	6337485.	0.	0.%	2563490.	40.%	2433166.	38.%	2.%	2.%
1991	0.	5330583.	0.	0.%	1639592.	31.%	2601095.	49.%	-18.%	-18.%
1992	0.	5047537.	0.	0.%	1220353.	24.%	2236974.	44.%	-20.%	-20.%
1993	0.	4862356.	0.	0.%	1829402.	38.%	2197784.	45.%	-8.%	-8.%
1994	0.	5874830.	0.	0.%	2155099.	37.%	1954453.	33.%	3.%	3.%
1995	0.	7390800.	0.	0.%	2159120.	29.%	2119861.	29.%	1.%	1.%

KENTUCKY POWER COMPANY   7-13-2005

ACCOUNT NO.: 10860000

DISTRIBUTION PLANT

			REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
YEAR	ADDITIONS	RETIREMENTS	AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1996	0.	6260150.	0.	0.%	1342053.	21.%	1245388.	20.%	2.%	2.%
1997	0.	8613849.	0.	0.%	1918643.	22.%	1444506.	17.%	6.%	6.%
1998	0.	5385836.	0.	0.%	1292253.	24.%	804413.	15.%	9.%	9.%
1999	0.	4764283.	0.	0.%	440710.	9.%	262682.	6.%	4.%	4.%
2000	0.	7883448.	0.	0.%	1501740.	19.%	213654.	3.%	16.%	16.%
2001	0.	5934590.	0.	0.%	2190111.	37.%	2918529.	49.%	-12.%	-12.%
2002	0.	6806995.	0.	0.%	5075585.	75.%	1403071.	21.%	54.%	54.%
2003	0.	5434672.	0.	0.%	1560605.	29.%	1192686.	22.%	7.%	7.%
2004	0.	7250554.	0.	0.%	2946107.	41.%	1979653.	27.%	13.%	13.%
	0.	164109276.	0.	0.%	64598859.	39.%	50710495.	31.%	8.%	8.%

ROLLING BAND

1954-1968	0.	10934864.	0.	0.%	4657056.	43.%	2911628.	27.%	16.%	16.%
1955-1969	0.	12149385.	0.	0.%	5139336.	42.%	3193044.	26.%	16.%	16.%
1956-1970	0.	12963305.	0.	0.%	5375740.	41.%	3481981.	27.%	15.%	15.%
1957-1971	0.	13938508.	0.	0.%	5744058.	41.%	3801858.	27.%	14.%	14.%
1958-1972	0.	14853407.	0.	0.%	6253413.	42.%	4150764.	28.%	14.%	14.%
1959-1973	0.	16121282.	0.	0.%	6750417.	42.%	4497710.	28.%	14.%	14.%
1960-1974	0.	16770340.	0.	0.%	7412551.	44.%	4873419.	29.%	15.%	15.%
1961-1975	0.	17691380.	0.	0.%	7774720.	44.%	5197271.	29.%	15.%	15.%
1962-1976	0.	18641914.	0.	0.%	8298665.	45.%	5707383.	31.%	14.%	14.%
1963-1977	0.	19874243.	0.	0.%	9031494.	45.%	6443431.	32.%	13.%	13.%
1964-1978	0.	22007076.	0.	0.%	10375192.	47.%	7201808.	33.%	14.%	14.%
1965-1979	0.	23613744.	0.	0.%	11439455.	48.%	8060280.	34.%	14.%	14.%
1966-1980	0.	25669409.	0.	0.%	12521258.	49.%	9244959.	36.%	13.%	13.%
1967-1981	0.	29090616.	0.	0.%	13954291.	48.%	10697097.	37.%	11.%	11.%
1968-1982	0.	30180037.	0.	0.%	15126880.	50.%	11857219.	39.%	11.%	11.%
1969-1983	0.	32767031.	0.	0.%	16016864.	49.%	12739006.	39.%	10.%	10.%
1970-1984	0.	33481838.	0.	0.%	16645378.	50.%	13855869.	41.%	8.%	8.%
1971-1985	0.	35728937.	0.	0.%	17278402.	48.%	14813519.	41.%	7.%	7.%
1972-1986	0.	38535755.	0.	0.%	18438359.	48.%	16226092.	42.%	6.%	6.%
1973-1987	0.	42123195.	0.	0.%	20027138.	48.%	17422002.	41.%	6.%	6.%
1974-1988	0.	45442640.	0.	0.%	21332524.	47.%	18812143.	41.%	6.%	6.%
1975-1989	0.	51454315.	0.	0.%	26138622.	51.%	20173346.	39.%	12.%	12.%
1976-1990	0.	56377911.	0.	0.%	28068762.	50.%	22121024.	39.%	11.%	11.%
1977-1991	0.	59937991.	0.	0.%	28803298.	48.%	24041676.	40.%	8.%	8.%
1978-1992	0.	63195003.	0.	0.%	28991434.	46.%	25349920.	40.%	6.%	6.%
1979-1993	0.	65217549.	0.	0.%	29198022.	45.%	26594907.	41.%	4.%	4.%
1980-1994	0.	68712684.	0.	0.%	29984190.	44.%	27501066.	40.%	4.%	4.%

KENTUCKY POWER COMPANY 7-13-2005

ACCOUNT NO.: 10860000

DISTRIBUTION PLANT

			REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
YEAR	ADDITIONS	RETIREMENTS	AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1981-1995	0.	73035598.	0.	0.%	30687384.	42.%	28197113.	39.%	3.%	3.%
1982-1996	0.	74803442.	0.	0.%	30146055.	40.%	27705260.	37.%	3.%	3.%
1983-1997	0.	80864707.	0.	0.%	30478220.	38.%	27646743.	34.%	4.%	4.%
1984-1998	0.	82332839.	0.	0.%	30210041.	37.%	27089586.	33.%	4.%	4.%
1985-1999	0.	84822180.	0.	0.%	29375704.	35.%	25887788.	31.%	4.%	4.%
1986-2000	0.	89314814.	0.	0.%	29844198.	33.%	24785895.	28.%	6.%	6.%
1987-2001	0.	91126983.	0.	0.%	30330395.	33.%	25890130.	28.%	5.%	5.%
1988-2002	0.	92871109.	0.	0.%	33064612.	36.%	25606454.	28.%	8.%	8.%
1989-2003	0.	93213086.	0.	0.%	32616019.	35.%	24917261.	27.%	8.%	8.%
1990-2004	0.	93177968.	0.	0.%	29834863.	32.%	25007915.	27.%	5.%	5.%

KENTUCKY POWER COMPANY
Distribution Plant Net Salvage Test

18-Jul-05

Retirements

Year	361	362	364	365	366	367	368	369	370	371	373	Total	Removal %	Weighted (000)
1990	2,108	289,306	2,752,129	1,114,551	7,201	11,675	959,910	396,795	383,340	261,542	73,803	6,232,360	2%	128
1991	4,188	308,885	1,480,558	1,060,633	1,608	19,317	1,219,271	456,573	293,127	317,371	48,804	5,210,115	-18%	-940
1992	0	107,270	1,465,072	909,965	0	69,723	1,618,101	415,580	381,788	292,580	21,277	5,281,356	-20%	-1,064
1993	972	176,465	1,304,149	758,447	0	9,042	1,105,636	696,650	502,234	349,338	27,095	4,930,028	-8%	-374
1994	19,675	267,934	144,412	1,379,552	199	18,365	1,164,053	562,102	576,545	354,006	37,451	4,524,294	3%	155
1995	2,757	287,579	1,671,011	2,549,129	5,842	19,071	1,313,309	497,449	631,063	350,093	30,017	7,357,320	1%	39
1996	5,030	454,597	1,128,837	1,662,236	1,248	37,421	1,578,917	475,561	517,207	246,115	18,665	6,125,834	2%	95
1997	6,522	734,060	1,542,829	1,668,505	4,035	46,345	2,186,374	522,610	836,156	529,850	26,937	8,102,223	6%	446
1998	57,059	430,669	1,082,705	867,054	1,777	16,729	1,560,837	431,172	723,727	553,968	20,374	5,746,071	9%	520
1999	462	133,384	779,722	767,232	2,608	11,656	1,278,242	344,602	979,544	465,115	15,450	4,778,017	4%	179
2000	0	430,936	1,459,576	1,553,565	6,479	36,661	1,443,110	569,287	1,709,961	637,697	26,217	7,873,489	16%	1,286
2001	0	543,501	1,402,184	1,323,285	9,421	11,194	1,029,459	390,080	639,511	583,686	22,268	5,934,589	-12%	-728
2002	0	163,287	1,100,199	2,020,300	16,953	71,261	1,055,795	508,684	970,185	370,170	27,698	6,304,532	54%	3,401
2003	0	448,926	770,546	1,665,159	2,929	23,089	1,073,924	630,850	624,632	155,456	19,163	5,414,676	7%	367
2004	370	325,880	3,284,700	1,048,651	2,052	37,052	1,076,234	511,999	832,607	115,921	33,892	7,249,358	13%	966
TOTAL	99,143	5,102,659	21,348,629	20,346,264	62,352	438,601	19,663,172	7,409,994	10,581,627	5,562,910	448,911	91,064,262	5%	4,477

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EVALUATION BASED ON 1990-2004 ACTUAL

	361	362	364	365	366	367	368	369	370	371	373	Total
Total Retmts	99,143	5,102,659	21,348,629	20,346,264	62,352	438,601	19,663,172	7,409,994	10,581,627	5,562,910	448,911	91,064,262
Gross Removal %	0	0	-40	20	0	15	25	15	25	0	-5	5
Gross Removal $	0	0	-8,539,452	4,069,253	0	65,790	4,915,793	1,111,499	2,645,407	0	-22,446	4,245,845

EXHIBIT JEH-1

KENTUCKY POWER COMPANY
Distribution Plant Salvage Test

18-Jul-05

Retirements

Year	361	362	364	365	366	367	368	369	370	371	373	Total	Salvage %	Weighted (000)
1990	2,108	289,306	2,752,129	1,114,551	7,201	11,675	959,910	396,795	363,340	261,542	73,803	6,232,360	40	249,294
1991	4,188	308,865	1,480,558	1,060,633	1,608	19,317	1,219,271	456,573	293,127	317,371	48,604	5,210,115	31	161,514
1992	0	107,270	1,465,072	909,965	0	69,723	1,618,101	415,580	381,788	292,580	21,277	5,281,356	24	126,753
1993	972	176,465	1,304,149	758,447	0	9,042	1,105,636	696,650	502,234	349,338	27,095	4,930,028	38	187,341
1994	19,675	267,934	144,412	1,379,552	199	18,365	1,164,053	562,102	576,545	354,006	37,451	4,524,294	37	167,399
1995	2,757	287,579	1,671,011	2,549,129	5,842	19,071	1,313,309	497,449	631,063	350,093	30,017	7,357,320	29	213,362
1996	5,030	454,597	1,128,837	1,662,236	1,248	37,421	1,578,917	475,561	517,207	246,115	18,665	6,125,834	21	128,643
1997	6,522	734,060	1,642,829	1,666,505	4,035	46,345	2,186,374	522,610	836,156	529,850	26,937	8,102,223	22	178,249
1998	57,059	430,669	1,082,705	867,054	1,777	16,729	1,580,837	431,172	723,727	553,968	20,374	5,746,071	24	137,906
1999	462	133,384	779,722	767,232	2,608	11,656	1,278,242	344,602	979,544	465,115	15,450	4,778,017	9	43,002
2000	0	430,936	1,459,576	1,553,565	6,479	36,661	1,443,110	569,287	1,709,961	637,697	26,217	7,873,489	19	149,596
2001	0	543,501	1,402,184	1,323,285	9,421	11,194	1,029,459	390,080	639,511	563,686	22,268	5,934,589	37	219,580
2002	0	163,287	1,100,199	2,020,300	16,953	71,261	1,055,795	508,684	970,185	370,170	27,698	6,304,532	75	472,840
2003	0	448,926	770,546	1,665,159	2,929	23,089	1,073,924	630,850	624,632	165,458	19,163	5,414,676	29	157,026
2004	370	325,880	3,264,700	1,046,651	2,052	37,052	1,076,234	511,999	832,607	115,921	33,892	7,249,358	41	297,224
TOTAL	99,143	5,102,659	21,348,629	20,346,264	62,352	438,601	19,663,172	7,409,994	10,581,627	5,582,910	448,911	91,064,262	32	2,889,727

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EVALUATION BASED ON 1990-2004 ACTUAL

	361	362	364	365	366	367	368	369	370	371	373	Total
Total Retmts	99,143	5,102,659	21,348,629	20,346,264	62,352	438,601	19,663,172	7,409,994	10,581,627	5,582,910	448,911	91,064,262
Gross Salvage, %	10	35	25	40	0	15	40	15	30	30	10	32
Gross Salvage $	9,914	1,785,931	5,337,157	8,138,506	0	65,790	7,865,269	1,111,499	3,174,488	1,668,873	44,891	29,202,318

EXHIBIT JEH-1

KENTUCKY POWER COMPANY
Distribution Plant Removal Test

18-Jul-05

Retirements

Year	361	362	364	365	366	367	368	369	370	371	373	Total	Removal %	Weighted (000)
1990	2,108	289,306	2,752,129	1,114,551	7,201	11,675	959,910	396,795	363,340	261,542	73,803	6,232,360	38	236,830
1991	4,188	308,865	1,480,558	1,060,633	1,608	19,317	1,219,271	456,573	293,127	317,371	48,604	5,210,115	49	255,296
1992	0	107,270	1,465,072	909,965	0	69,723	1,618,101	415,580	381,788	292,560	21,277	5,281,356	44	232,380
1993	972	176,465	1,304,149	758,447	0	9,042	1,105,636	696,650	502,234	349,338	27,095	4,930,028	45	221,851
1994	19,675	267,934	144,412	1,379,552	199	18,365	1,164,053	562,102	576,545	354,006	37,451	4,524,294	33	149,302
1995	2,757	287,579	1,671,011	2,549,129	5,842	19,071	1,313,309	497,449	631,063	350,093	30,017	7,357,320	29	213,362
1996	5,030	454,597	1,128,837	1,662,236	1,248	37,421	1,578,917	475,561	517,207	246,115	18,665	6,125,834	20	122,517
1997	6,522	734,060	1,542,829	1,666,505	4,035	46,345	2,186,374	522,610	836,156	529,850	26,937	8,102,223	17	137,738
1998	57,059	430,669	1,082,705	867,054	1,777	16,729	1,560,837	431,172	723,727	553,968	20,374	5,746,071	15	86,191
1999	462	133,384	779,722	767,232	2,608	11,656	1,278,242	344,602	979,544	465,115	15,450	4,778,017	6	28,668
2000	0	430,936	1,459,576	1,553,565	6,479	38,661	1,443,110	569,287	1,709,961	637,697	28,217	7,873,489	3	23,620
2001	0	543,501	1,402,184	1,323,285	9,421	11,194	1,029,459	390,080	639,511	563,686	22,268	5,934,589	49	290,795
2002	0	163,287	1,100,199	2,020,300	16,953	71,261	1,055,795	508,684	970,185	370,170	27,698	6,304,532	21	132,395
2003	0	448,926	770,546	1,665,159	2,929	23,089	1,073,924	630,850	624,632	155,458	19,163	5,414,676	22	119,123
2004	370	325,880	3,264,700	1,048,651	2,052	37,052	1,076,234	511,999	832,607	115,921	33,892	7,249,358	27	195,733
TOTAL	99,143	5,102,659	21,348,629	20,346,264	62,352	438,601	19,663,172	7,409,994	10,581,627	5,562,910	448,911	91,064,262	27	2,445,800

A11

EVALUATION BASED ON 1990-2004 ACTUAL

	361	362	364	365	366	367	368	369	370	371	373	Total
Total Retmts	99,143	5,102,659	21,348,629	20,346,264	62,352	438,601	19,663,172	7,409,994	10,581,627	5,562,910	448,911	91,064,262
Gross Removal %	10	35	65	20	0	0	15	0	5	30	15	27
Gross Removal $	9,914	1,785,931	13,876,609	4,069,253	0	0	2,949,476	0	529,081	1,668,873	67,337	24,956,473

EXHIBIT JEH-1

AVERAGE LIFE GROUP METHOD THEORETICAL RESERVE

ACCOUNT 35300000

AGE	VINTAGE YEAR	SURVIVING BALANCE 12/31/2004	REMAINING LIFE ASL CURVE 40.0 R1.5	RESERVE RATIO	THEORETICAL RESERVE
0.5	2004	2525237.	39.5887	0.01028	25965.
1.5	2003	4440859.	38.7692	0.03077	136646.
2.5	2002	4425166.	37.9554	0.05111	226192.
3.5	2001	3138656.	37.1474	0.07132	223836.
4.5	2000	2485512.	36.3451	0.09137	227105.
5.5	1999	1488533.	35.5487	0.11128	165648.
6.5	1998	11141156.	34.7581	0.13105	1460008.
7.5	1997	36890866.	33.9735	0.15066	5558101.
8.5	1996	2460717.	33.1947	0.17013	418650.
9.5	1995	853676.	32.4218	0.18945	161733.
10.5	1994	2257709.	31.6549	0.20863	471020.
11.5	1993	5784518.	30.8940	0.22765	1316845.
12.5	1992	2135657.	30.1391	0.24652	526485.
13.5	1991	3781093.	29.3905	0.26524	1002892.
14.5	1990	3006144.	28.6482	0.28379	853128.
15.5	1989	1310459.	27.9126	0.30219	396001.
16.5	1988	530915.	27.1840	0.32040	170105.
17.5	1987	2172360.	26.4627	0.33843	735197.
18.5	1986	499860.	25.7490	0.35628	178088.
19.5	1985	740900.	25.0433	0.37392	277035.
20.5	1984	1222401.	24.3459	0.39135	478388.
21.5	1983	1373085.	23.6572	0.40857	561001.
22.5	1982	1403128.	22.9775	0.42556	597117.
23.5	1981	7231608.	22.3072	0.44232	3198689.
24.5	1980	5873681.	21.6466	0.45884	2695057.
25.5	1979	966417.	20.9960	0.47510	459146.
26.5	1978	54599.	20.3557	0.49111	26814.
27.5	1977	2064405.	19.7261	0.50685	1046341.
28.5	1976	1092819.	19.1074	0.52232	570797.
29.5	1975	763727.	18.5000	0.53750	410504.
30.5	1974	1070195.	17.9041	0.55240	591173.
31.5	1973	165119.	17.3200	0.56700	93622.
32.5	1972	169122.	16.7480	0.58130	98311.

AVERAGE LIFE GROUP METHOD THEORETICAL RESERVE
ACCOUNT 35300000

AGE	VINTAGE YEAR	SURVIVING BALANCE 12/31/2004	REMAINING LIFE ASL CURVE 40.0 R1.5	RESERVE RATIO	THEORETICAL RESERVE
33.5	1971	207616.	16.1882	0.59530	123593.
34.5	1970	700895.	15.6409	0.60898	426829.
35.5	1969	5275929.	15.1064	0.62234	3283426.
36.5	1968	59424.	14.5846	0.63539	37757.
37.5	1967	307861.	14.0758	0.64810	199526.
38.5	1966	5843.	13.5802	0.66050	3859.
39.5	1965	103552.	13.0976	0.67256	69645.
40.5	1964	12210.	12.6282	0.68430	8355.
41.5	1963	560961.	12.1719	0.69570	390262.
42.5	1962	5906.	11.7287	0.70678	4174.
43.5	1961	347.	11.2984	0.71756	249.
44.5	1960	25384.	10.8807	0.72798	18479.
45.5	1959	54101.	10.4755	0.73811	39933.
46.5	1958	577.	10.0824	0.74794	432.
47.5	1957	8981.	9.7011	0.75747	6803.
49.5	1955	897.	8.9715	0.77571	696.
50.5	1954	294758.	8.6222	0.78444	231221.
51.5	1953	7575.	8.2824	0.79294	6007.
		123153116.			30208887.
			NET SALVAGE VALUE(%)		0.
			RESERVE AFTER SALVAGE		30208886.
			REMAINING LIFE (YRS)		30.19

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY   CASE NO. 2005-000341

DIRECT TESTIMONY
OF
PAUL R. MOUL

ON BEHALF OF
KENTUCKY POWER COMPANY

September 26, 2005

Kentucky Power Company
Direct Testimony of Paul R. Moul
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GLOSSARY OF ACRONYMS AND DEFINED TERMS

ACRONYM	DEFINED TERM
AEP	American Electric Power Company
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
DCF	Discounted Cash Flow
EPACT	National Energy Policy Act
FERC	Federal Energy Regulatory Commission
FFO	Funds from operations
FOMC	Federal Open Market Committee
g	Growth rate
GDP	Gross Domestic Product
IGCC	Integrated Gasification Cycle
IGF	Internally Generated Funds
Lev	Leverage modification
LT	Long Term
MLP	Master Limited Partnerships
MM	Modigliani & Miller
NUGS	Non-utility Generators
PUC	Public Utility Commission
r	represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Market risk premium
RP	Risk Premium

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
RTOs	Regional Transmission Organizations
s	represents the new common shares expected to be issued by a firm
s x v	Represents external growth
S&P	Standard & Poor's
v	represents the value that accrues to existing shareholders from selling stock at a price different from book value

DIRECT TESTIMONY OF
PAUL R. MOUL, ON BEHALF OF
KENTUCKY POWER COMPANY,
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
CASE NO. 2005-000341

INTRODUCTION AND SUMMARY OF RECOMMENDATION

Q: Please state your name and address.

A: My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, NJ 08033-3062. I am Managing Consultant of the firm P. Moul & Associates, an independent, financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in Appendix A that follows my direct testimony.

Q: What is the purpose of your testimony?

A: My testimony presents evidence, analysis, and a recommendation concerning the appropriate rate of return on common equity that the Public Service Commission of the Commonwealth of Kentucky (the "Commission") should allow Kentucky Power Company ("Kentucky Power" or the "Company") an opportunity to earn on its investment. My analysis and recommendation is supported by the detailed financial data contained in Exhibit PRM-1 that is a multi-page document divided into thirteen (13) schedules. Additional evidence, in the form of appendices, follows my direct testimony. The items covered in these appendices deal with the technical aspects of my testimony.

Q: Based upon your analysis, what is your conclusion concerning the appropriate rate of return on common equity for Kentucky Power in this case?

A: My conclusion is that the Company should be afforded an opportunity to earn a rate of return on common equity of 11.50%. My recommended rate of return on common equity of 11.50% is used in conjunction with the capital structure ratios and capital cost rates developed by the Company's witness Mr. Errol K. Wagner as contained in Section V, Workpaper S-2, page 1 of 3. That calculation produces a 7.89% post-tax overall rate of return. The weighted average cost of capital when applied to the Company's rate base will compensate investors for the use of their capital and permit it to attract capital.

Q: How have you determined the rate of return on common equity in this case?

A: In arriving at my recommended rate of return on common equity, I employed capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for an electric utility, such as Kentucky Power. In this regard, I relied on four well-recognized measures of the cost of equity: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings approach. By considering the results of a variety of approaches, I determined that an 11.50% rate of return on common equity is reasonable for Kentucky Power. The procedure that I used to reach my recommendation reflects the well-recognized principles for determining a fair rate of return.

Q: In your opinion, what factors should the Commission consider when setting the Company's cost of capital in this proceeding?

A: The Commission should consider the rate-setting principles that I have set forth in Appendix B. The end result of the Commission's rate of return allowance must provide the Company with an opportunity to cover its interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be adequate to attract capital, be commensurate with the risk to which the Company's capital is exposed, and support reasonable credit quality.

Q: What factors have you considered in determining the cost of equity in this case?

A: The models that I used to measure the rate of return on common equity for the Company were applied with market and financial data developed from a proxy group of eight companies that own public utilities. The proxy group consists of publicly-traded companies that are included in The Value Line Investment Survey, whose electric utility subsidiaries operate in the Great Lakes region of the U.S. according to the definition by S&P Compustat, have not recently reduced their common dividend, and are not currently the target of a merger or acquisition. The companies in the proxy group are identified on page 2 of Schedule 3. I will refer to these companies as the "Electric Group" throughout my testimony.

Q: Please summarize your cost of equity analysis for the Electric Group.

A: My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. The following table provides a summary of the indicated costs of equity using each of these approaches.

	Excluding Flotation Costs [1]	Including Flotation Costs [1]
DCF	11.12%	11.33%
Risk Premium	11.25%	11.46%
CAPM	11.31%	11.52%
Comparable Earnings	13.55%	13.55%

Focusing upon the market models of the cost of equity (i.e., DCF, Risk Premium and CAPM), the equity return is 11.23% (11.12% + 11.25% + 11.31% = 33.68% ÷ 3) excluding flotation costs and is 11.44% (11.33% + 11.46% + 11.52% = 34.31% ÷ 3) including flotation costs. The mean and median of all methods is 11.81% and 11.28%, respectively, excluding flotation costs, and is 11.97% and 11.49%, respectively, including flotation costs. The medians in this regard are a measure of central tendency, and in this case are represented by the Risk Premium and CAPM results. From these measures, I have recommended that the Company use an 11.50% rate of return on common equity to calculate its weight average cost of capital.

ELECTRIC UTILITY RISK FACTORS

Q: What background information have you considered in analyzing the Company's rate of return on common equity?

A: Kentucky Power is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP" or the "Parent Company"). The common stock of AEP is traded on the New York Stock Exchange. AEP is a component of the Dow Jones

[1] Flotation costs are defined as the out-of-pocket costs associated with the issuance of common stock. Those costs typically consist of the underwriters' discount and company issuance expenses.

Utility Average, Standard & Poor's Public Utility Index, and the S&P 500 Composite Index.

The Company is engaged in the generation, purchase, sale, transmission and distribution of electricity to approximately 175,000 retail customers in eastern Kentucky. In 2004, the Company's KwH sales were represented by approximately 34% to residential, 20% to commercial, and 46% to industrial customers. While representing 46% of retail sales, industrial customers comprise less than one-percent of the Company's customers. This means that the electricity needs of a few customers have a significant impact on the Company's operations.

Q: Please discuss the evolving risk issues for electric utilities.

A: Under the rules of Order No. 2000, RTOs have been formed as independent entities that offer non-discriminatory transmission service. Kentucky Power, as part of AEP, is part of the PJM Interconnection LLC, a FERC recognized RTO. The recent passage of the Energy Policy Act of 2005 also highlights the emphasis being placed upon the reliability and structure of the electric utility industry. Aside from their traditional responsibility to supply adequate capacity to meet forecast loads (in a more uncertain market), and to comply with increasingly stringent environmental standards, increasing competitive risks are now evolving in a new era for electric utilities. Some electric utilities, including Kentucky Power, face substantial increases in operating and capital costs to comply with the Clean Air Act ("CAA"). These investments do not add to an electric utility's generating capacity, but rather they represent cost increases that create added risk for the electric utilities. Environmental risk becomes aggravated by the recurring series of new laws and regulations. The "moving target" of environmental regulation pressures the operations and rate structures of public utilities. Although there has been increased emphasis on market-determined prices and open access of the transmission network, pricing policies of public utilities in substantial measure are restrained by regulation, while other non-regulated firms have greater latitude in adjusting their prices and in responding to changing market conditions. Hence, deregulation of certain segments of the electric utility business provides downside risk due to loss of revenues, but provides little upside potential for the regulated portion due to the limitations placed on returns by regulators.

Q: Are there other specific risk issues facing Kentucky Power?

A: Yes. The Company's risk profile is strongly influenced by electricity sold/delivered to industrial customers. The deliveries to industrial customers represent nearly one-half of direct sales of energy by the Company. The Company's largest customers are engaged in chemicals, mining, petroleum refining, and primary metals. For some industrial sales, the Company faces significant loss of load as the price of electricity rises. Sales to high volume customers are generally considered to be of higher risk than sales to other classes of customers. Success in this segment of the Company's market is subject to (i) the business cycle, (ii) the price of alternative energy sources, and (iii) pressures from alternative providers. Moreover, external factors can also influence the Company's sales to these customers which face competitive pressures on their own operations from other facilities outside the Company's service territory.

Q: Please indicate how the Company's risk profile is affected by its construction program.

A: The Company is faced with the requirement to undertake investment to maintain and upgrade existing facilities in its service territory, including expenditures to comply with the CAA, and to meet growth. Over the next five years, the Company expects that its total capital expenditures will represent a significant increase in net utility plant from the level at December 31, 2004. In addition, the Company will require large amounts of new investor provided capital to finance its construction because internally generated funds will be inadequate in this regard. As previously noted, a fair rate of return for the Company represents a key to a financial profile that will provide the Company with the ability to raise the capital necessary to meet its capital needs on an ongoing basis. In the situation where additional capital is required, as shown by the construction expenditures indicated above, the regulatory process must establish a return on equity that provides a reasonable opportunity for the Company to actually earn its cost of capital.

FUNDAMENTAL RISK ANALYSIS

Q: Is it necessary to conduct a fundamental risk analysis to provide a framework for a determination of a utility's cost of equity?

A: Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors which bear upon the Company's risk have already been discussed. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and their required returns are described in Appendix C. For this purpose, I have utilized the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and the Electric Group.

Q: What are the components of the S&P Public Utilities?

A: The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 4. I have used this group as a broad-based measure of all types of utility companies.

Q: What criteria did you employ to assemble the Electric Group?

A: The Electric Group that I employed in this case includes companies that are (i) engaged in similar business lines, (ii) have publicly-traded common stock, (iii) are included in <u>The Value Line Investment Survey</u> (iv) operate within the Great Lakes region of the U.S. according to the definition by S&P Compustat, (v) have not recently reduced their common dividend, and (vi) are not currently the target of a merger or acquisition. The Electric Group includes Ameren, DTE Energy, Exelon, FirstEnergy, MGE Energy, Vectren, WPS Resources, and Wisconsin Energy.

Q: Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A: Yes. Knowledge of a company's credit quality rating is important because the cost of each type of capital is directly related to the associated risk of the firm. So while a company's credit quality risk is shown directly by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus compensation to recognize the higher risk of an equity investment compared to debt.

Q: How do the bond ratings compare for Kentucky Power, AEP, the Electric Group, and the S&P Public Utilities?

A: Presently, Kentucky Power's corporate credit rating ("CCR") is BBB from Standard and Poor's Corporation ("S&P") and the Long Term ("LT") issuer rating is Baa2 from Moody's Investors Services ("Moody's"). The CCR and LT ratings for AEP are BBB from S&P and Baa2 from Moody's. The CCR designation by S&P and LT issuer rating by Moody's focuses upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. The average credit quality of the Electric Group is an A- from S&P and A3 from Moody's. For the S&P Public Utilities, the average composite rating is BBB by S&P and Baa2 by Moody's. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q: How do the financial data compare for AEP, the Electric Group, and the S&P Public Utilities?

A: The broad categories of financial data that I will discuss are shown on Schedules 2, 3 and 4. The data cover the five-year period 2000-2004. For the purpose of my analysis, I have analyzed the historical results for AEP, the Electric Group and the S&P Public Utilities. I will highlight the important categories of relative risk as follows:

<u>Size</u>. In terms of capitalization, AEP is somewhat larger than the average size of the Electric Group and the S&P Public Utilities.

<u>Market Ratios</u>. Market-based financial ratios provide a partial indication of

the investor-required cost of equity. If all other factors are equal, investors will require a higher return on equity for companies that exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings. For example, two otherwise similarly situated firms each reporting $1.00 earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

The five-year average price-earnings multiple was higher for AEP as compared to the Electric Group and the S&P Public Utilities. The higher multiple in 2000 was related more to the poor earnings of AEP, rather than a measure of risk. The five-year average dividend yield was higher for AEP as compared to the Electric Group and the S&P Public Utilities. The five-year average market-to-book ratio was highest for the S&P Public Utilities, followed by the Electric Group and then AEP.

<u>Common Equity Ratio</u>. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 38.1% for AEP, 44.2% for the Electric Group and 37.9% for the S&P Public Utilities.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relative levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.724 (5.5% ÷ 7.6%) for AEP, 0.084 (1.0% ÷ 11.8%) for the Electric Group, and 0.283 (2.8% ÷ 9.9%) for the S&P Public Utilities.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation and taxes other than income).[2] The five-year average operating ratios were 88.5% for AEP, 85.1% for the Electric Group, and 84.8% for the S&P Public Utilities.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average interest coverage (excluding AFUDC) was 2.22 times for AEP, 3.12 times for the Electric Group, and 2.56 times for the S&P Public Utilities.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of Allowance for Funds Used During Construction ("AFUDC") related to income available for common equity, the effective income tax rate, and

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[2] The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for AEP, the Electric Group, and the S&P Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 99.4% for AEP, 98.2% for the Electric Group, and 107.1% for the S&P Public Utilities. For AEP, capital expenditures are forecast to increase significantly in the future, which will pressure the IGF percentage. For example, AEP estimates that environmental investment will be approximately $4 billion, of which approximately $319 million will be spent in Kentucky. In addition, another estimated $1 billion is expected to be invested in a 600 mW Integrated Gasification Combined Cycle ("IGCC") generating plant. Consideration is also being given to construction of an additional IGCC plant. As such, IGF to construction will likely fall, absent a radical change in IGF for the future.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities. Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line betas provided on page 3 of Schedule 4 -- 1.15 for AEP, page 2 of

Schedule 3 -- .72 as the average for the Electric Group, and page 3 of Schedule 4 -- .95 as the average for the S&P Public Utilities. Keeping in mind that the utility industry has changed dramatically during the past five years, the systematic risk percentage is 121% (1.15 ÷ .95) for AEP and 76% (.72 ÷ .95) for the Electric Group using S&P Public Utilities' average beta as a benchmark.

Q: Please summarize your risk evaluation of AEP and the Electric Group.

A: AEP has a lower common equity ratio, it has higher earnings variability, and has lower credit quality as compared to the Electric Group. Further, as noted previously, Kentucky Power has very substantial construction requirements for the future, and its sales are highly influenced by industrial customers. Overall, the fundamental risk factors indicate that the Electric Group provides a conservative basis for measuring the Company's cost of equity.

COST OF EQUITY – GENERAL APPROACH

Q: Please describe the process you employed to determine the cost of equity for the Company.

A: Although my fundamental financial analysis provides the required framework to establish the risk relationships between the Electric Group and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I describe in Appendix D. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As noted in Appendix D, and elsewhere in my direct testimony, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Electric Group and have arrived at a cost of equity of 11.50% for the Company.

DISCOUNTED CASH FLOW ANALYSIS

Q: Please describe your use of the Discounted Cash Flow approach to determine the cost of equity.

A: The details of my use of the DCF approach and the calculations and evidence in support of my conclusions are set forth in Appendix E. I will summarize them here. The Discounted Cash Flow ("DCF") model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stocks consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The cost of equity that I have determined using the traditional form of the DCF model is 10.53% as described below. I have also presented an alternative form of the DCF model that provides a cost of equity of 12.12%. By considering both forms of the model, I have determined a DCF cost of equity of 11.33%.

Among other limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

As I describe in Appendix E, the DCF approach has other limitations that diminish its usefulness in the ratesetting process when the market capitalization diverge significantly from the book value capitalization. When this situation exists, the DCF method will lead to a misspecified cost of equity when it is applied to a book value capital structure.

Q: Please explain the dividend yield component of a DCF analysis.

A: The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended June 2005, the monthly dividend yields of the Electric Group are shown graphically on Schedule 5. The monthly dividend yields shown on Schedule 5 reflect an adjustment to the month-end prices to reflect the build up of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment). An explanation of this adjustment is provided in Appendix E.

For the twelve months ending June 2005, the average dividend yield was 4.09% for the Electric Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three- month periods were 3.96% and 3.85%, respectively. I have used, for the purpose of my direct testimony, a dividend yield of 3.96% for the Electric Group, which represents the six-month average yield. The use of this dividend yield will reflect current capital costs while avoiding spot yields.

For the purpose of a DCF calculation, the average dividend yields must be adjusted to reflect the prospective nature of the dividend payments i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investor anticipated cash flows for the Electric Group. I have adjusted the six-month average dividend yield in three different but generally accepted manners, and used the average of the three adjusted values as calculated in Appendix E. That adjusted dividend yield is 4.08% for the Electric Group.

Q: Please explain the underlying factors that influence investor's growth expectations.

A: As noted previously, investors are interested principally in the future growth of their investment (i.e., the price per share of the stock). As I explain in Appendix E, future earnings per share growth represents their primary focus because under the constant price-earnings multiple assumption of the DCF model, the price per share of stock will grow at the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth. The variables that can be considered include: earnings, dividends, book value, and cash flow stated on a per share basis. Historical values for these variables can be considered, as well as analysts' forecasts that are widely available to investors. A fundamental growth rate analysis can also be formulated, which consists of internal growth ("bxr"), where "r" represents the expected rate of return on common equity and "b" is the retention rate that consists of the fraction of earnings that are not paid out as dividends. The internal growth rate can be modified to account for sales of new common stock -- this is called external growth ("sxv"), where "s" represents the new common shares expected to be issued by a firm and "v" represents the value that accrues to existing shareholders from selling stock at a price different from book value. Fundamental growth, which combines internal and external growth, provides an explanation of the factors that cause book value per share to grow over time. Hence, a fundamental growth rate analysis is duplicative of expected book value per share growth.

Growth can also be expressed in multiple stages. This expression of growth consists of an initial "growth" stage where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage where fewer technological advances and increased product saturation begins to reduce the growth rate and profit margins come under pressure. During the "transition" phase, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity stabilizes at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps-up and ramps-down in cycles over time.

Q: What investor-expected growth rate is appropriate in a DCF calculation?

A: Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. I follow an approach that is not rigidly formatted because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner. Therefore, in my opinion, all relevant growth rate indicators using a variety of techniques must be evaluated when formulating a judgment of investor expected growth.

Q: Before presenting your analysis of the growth rates that apply specifically to the Electric Group, can you provide an overview of the macroeconomic factors that influence investor growth expectations for common stocks?

A: Yes. As a preliminary matter, it is useful to view macroeconomic forecasts that influence stock prices. Forecast growth of the Gross Domestic Product ("GDP") can represent the starting point for this analysis. The GDP has both "product side" and "income side" components. The product side of the GDP is comprised of: (i) personal consumption expenditures; (ii) gross private domestic investment; (iii) net exports of goods and services; and (iv) government consumption expenditures and gross investment. On the income side of the GDP, the components are: (i) compensation of employees; (ii) proprietors' income; (iii) rental income; (iv) corporate profits; (v) net interest; (vi) business transfer payments; (vii) indirect business taxes; (viii) consumption of fixed capital; (ix) net receipts/payment to the rest of the world; and (x) statistical discrepancy. The "product side," (i.e., demand components) could be used as a long-term representation of revenue growth for public utilities. However, it is well known that revenue growth does not necessarily equal earnings growth. There is no basis to assume that the same growth rate would apply to revenues and all components of the cost of service, especially after the troublesome issues of employees' costs, insurance costs, high fuel costs and environmental costs are worked-out in the long-term for public utilities. The earnings growth rates for utilities will be substantially affected by fluctuations in operating expenses and capital costs.

The long-term consensus forecast that is published semi-annually by the Blue Chip Economic Indicators ("Blue Chip") should be used as the source of macroeconomic growth. Blue Chip is a monthly publication that provides forecasts incorporating a wide variety of economic variables assembled from a panel of more than 50 noted economists from the banking, investment, industrial, and consulting sectors whose advice affects the investment activities of market participants. It is always preferable to use a consensus forecast taken from a large panel of contributors, rather than to rely upon one source that may not be representative of the types of information that have an impact on investor expectations. Indeed, Blue Chip is frequently quoted in "The Wall Street Journal," "The New York Times," "Fortune," "Forbes," and "Business Week." Twice annually, Blue Chip provides long-range consensus forecasts. Based upon the March 10, 2005 issue of Blue

Chip, those forecasts are:

Blue Chip Economic Indicators		
Year	Nominal GDP	Corporate Profits, Pretax
2007	5.3%	5.5%
2008	5.2%	5.2%
2009	5.2%	5.1%
2010	5.4%	6.4%
2011	5.4%	6.7%
Averages		
2007-11	5.3%	5.8%
2012-16	5.3%	6.3%

These forecasts show that growth in corporate profits will generally exceed growth in overall GDP. It is also indicated historically that the percentage change in corporate profits has been higher than the percentage change in GDP.[3] From these data, growth in corporate profits of 6% would represent an overall benchmark for the long-term growth component of the DCF.

Q: What company-specific data have you considered in your growth rate analysis?

A: I have considered the growth in the financial variables shown on Schedules 6 and 7. The bar graph provided on Schedule 6 shows the historical growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Electric Group. The historical growth rates were taken from the Value Line publication that provides these data. As shown on Schedule 6, the historical earnings per share growth rates were 5.58% and 0.92% for the Electric Group. The historical growth rates contain instances of negative values for individual

[3] Obviously, growth in corporate profits are negatively impacted during recessionary periods, but on average corporate profits have grown historically over two percentage points faster than GDP since the 1934.

companies within the Electric Group. Although indications of negative growth should not be considered for reasons stated below, both positive and negative growth rates have been included in the averages for the Electric Group. Negative growth rates provide no reliable guide to gauge investor expected growth for the future. Investor expectations encompass long-term positive growth rates and, as such, could not be represented by sustainable negative rates of change. Therefore, statistics that include negative growth rates should not be given any weight when formulating a composite growth rate expectation. The prospect of rate increases granted by regulators, the continued obligation to provide service as required by customers, and the ongoing growth of customers mandate investor expectations of positive future growth rates. Stated simply, there is no reason for investors to expect that a utility will wind up its business and distribute its common equity capital to shareholders, which would be symptomatic of a long-term permanent earnings decline. Although investors have knowledge that negative growth and losses can occur, their expectations include positive growth. Negative historic values will not provide a reasonable representation of future growth expectations because, in the long run, investors will expect positive growth. Indeed, rational investors always expect positive returns, otherwise they will hold cash rather than invest with the expectation of a loss.

Schedule 7 provides projected earnings per share growth rates taken from analysts' forecasts compiled by IBES/First Call, Zacks, and Reuters/Market Guide and from the Value Line publication. IBES/First Call, Zacks, and Reuters/Market Guide represent reliable authorities of projected growth upon which investors rely.

The IBES/First Call, Zacks, and Reuters/Market Guide forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share have also been included on Schedule 7 for the Electric Group.

Although five-year forecasts usually receive the most attention in the growth analysis for DCF purposes, present market performance has been strongly influenced by short-term earnings forecasts. Each of the major publications provides earnings forecasts for the current and subsequent year. These short-term earnings forecasts receive prominent coverage, and indeed they dominate these publications. While the DCF model typically focuses upon long-run estimates of earnings, stock prices are clearly influenced by current and near-term earnings forecasts.

Q: Is a five-year investment horizon associated with the analysts' forecasts consistent with the DCF model?

A: Yes. In fact, it illustrates that the infinite form of the model contains an unrealistic assumption. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investor expected return. The growth in the price per share will equal the growth in earnings per share absent any change in price-earnings (P-E) multiple -- a necessary assumption of the DCF. As such, my company-specific growth analysis, which focuses principally upon five-year forecasts of earnings per share growth, conforms with the type of analysis that influences the total return expectation of investors. Moreover, academic research focuses on five-year growth rates as they influence stock prices. Indeed, if investors really required forecasts which extended beyond five years in order to properly value common stocks, then I am sure that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of investors. The absence of such a publication signals that investors do not require infinite forecasts in order to purchase and sell stocks in the marketplace.

Q: What specific evidence have you considered in the DCF growth analysis?

A: As to the five-year forecast growth rates, Schedule 7 indicates that the projected earnings per share growth rates for the Electric Group are 4.51% by IBES/First Call, 5.07% by Zacks, 5.27% by Reuters/Market Guide, and 5.63% by Value Line. The Value Line projections indicate that earnings per share for the Electric Group will grow prospectively at a more rapid rate (i.e., 5.63%) than the dividends per share (i.e., 3.64%), which indicates a declining dividend payout ratio for the future. As indicated earlier, and in Appendix E, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

Q: What conclusion have you drawn from these data?

A: Although ideally historical and projected earnings per share and dividends per share growth indicators would be used to provide an assessment of investor growth expectations for a firm, the circumstances of the Electric Group mandate that the greater emphasis be placed upon projected earnings per share growth. The massive restructuring of the utility industry suggests that historical evidence alone does not represent a complete measure of growth for these companies. Rather, projections of future earnings growth provide the principal focus of investor expectations. In this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is forecasts of earnings per share growth. Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, Reuters/Market Guide, and Value Line, represents a reasonable assessment of investor expectations.

It is appropriate to consider all forecasts of earnings growth rates that are available to investors. In this regard, I have considered the forecasts from IBES/First Call, Zacks, Reuters/Market Guide and Value Line. The IBES/First Call, Zacks, and Reuters/Market Guide growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, Zacks, and Reuters/Market Guide estimates are obtained from the Internet and are widely available to investors free-of-charge. First Call is probably quoted most frequently in the financial press when reporting on earnings forecasts. The Value Line forecasts are also widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries.

The forecasts of earnings per share growth as shown on Schedule 7 provide a range of growth rates of 4.51% to 5.63%. To those company-specific growth rates, consideration must be given to the 6% long-term growth in corporate profits. While the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 5.50% is within the array of earnings per share growth rates shown by the analysts' forecasts and the forecast growth in overall corporate profits. The Value Line forecast of dividend per share growth is inadequate in this regard due to the forecast decline in the dividend payout that I previously described. As previously indicated, the restructuring and consolidation now taking place in the utility industry, will provide additional risks and opportunities as the utility industry successfully adapts to the new business environment. These changes in growth fundamentals will undoubtedly develop beyond the next five years typically considered in the analysts' forecasts that will enhance the growth prospects for the future. As such, a 5.50% growth rate will accommodate all these factors.

Q: Does the sum of the dividend yield and growth rate provide a complete representation of the cost of equity?

A. No.

Q. Please explain why.

A: As demonstrated in Appendix E, the divergence of stock prices from book values creates a conflict when the results of a market-derived cost of equity are applied to the common equity account measured at book value, which is the measure used in calculating the weighted average cost of capital. This is the situation today where the market price of stock exceeds its book value for most utilities. This divergence of price and book value creates a financial risk difference, whereby the capitalization of a utility measured at its market value contains relatively less debt and more equity than the capitalization measured at its book value.

If regulators rely upon the results of the DCF (which are based on the market price of the stock of the companies analyzed) and apply those results to a book value capital structure, there would be a mismatch of the financial risk associated with the more highly leveraged book value capital structure. This shortcoming of the DCF has persuaded one regulatory agency to adjust the cost of equity upward to make the return consistent with the book value capital structure. The Pennsylvania Public Utility Commission in its Order entered December 22, 2004 involving PPL Electric Utilities Corporation at Docket No. R-00049255 acknowledged that an adjustment to the DCF results was required to make the return consistent with the book value capital structure. In that decision, the Pennsylvania PUC provided PPL (a wires-only electric delivery utility) with an additional 45 basis points to the simple DCF derived cost of equity for the financial risk difference related to the divergence of the market capitalization from the book value capitalization. Similar provisions were made by the Pennsylvania PUC in its decisions dated January 10, 2002 for Pennsylvania-American Water Company at Docket No. R-00016339, dated August 1, 2002 for Philadelphia Suburban Water Company in Docket No. R-00016750, dated January 29, 2004 for Pennsylvania American Water Company at Docket No. R-00038304 (affirmed by the Commonwealth Court on November 8, 2004), and dated August 5, 2004 for Aqua

Pennsylvania, Inc. at Docket No. R-00038805. It must be recognized that in order to make the DCF results relevant to the capitalization measured at book value (as is done for rate setting purposes), the market-derived cost rate cannot be used without modification. As I will explain later in my testimony, the DCF model can be modified to account for differences in risk attributed to changes in financial leverage when market prices and book values diverge.

Q: Have you previously presented this modification to the Commission in the Company's prior rate case proceedings?

A: Yes. In the Company's prior rate case (Case No. 2002-0016), I presented this adjustment. In that case, the Commission agreed with the AG's argument against adjusting the ROE for the leverage risk difference. The reasons set forth by the AG in opposition to the leverage adjustment included: (i) investors are aware that the book value capital structure is used to determine rates, (ii) the adjustment formula contains some unrealistic assumptions, and (iii) that once unlevered, the cost of equity should be re-levered using the Company's capital structure rather than the proxy group's capital structure. The Commission further noted that the instability of the market value of equity creates problems with the leverage adjustment and investors should have already incorporated the difference between book value and the market's valuation of a utility's stock.

Q: Please respond.

A: Unfortunately, in the Company's prior case, I may have provided insufficient explanation of the underpinnings of the leverage adjustment. Had I done so, it would have been apparent that none of these criticisms of my leverage adjustment provides a basis to ignore it. The adjustment addresses the single issue of financial risk, and is not dependent upon any particular price to book relationships as suggested in the Commission's order. The leverage adjustment contains no target price to book ratio. Rather my adjustment provides recognition of the financial risk difference between the market capitalization and the book value capitalization. Indeed, there is no input variable for any price to book ratio in the formulas that I have employed. As to the issue of market instability regarding my leverage adjustment, the adjustment adds stability to the overall DCF result. That is to say, as the market capitalization moves higher in relation to the book value capitalization, then the leverage adjustment increases as the dividend yield declines. Conversely, as the market capitalization declines by reference to the book value capitalization, the leverage adjustment also declines as the dividend yield increases. The counterbalancing feature of the leverage adjustment and the dividend yield actually provide increased stability to the overall DCF results. Furthermore, while investors may be aware that the book value is used to determine capital structure ratios for ratesetting, they are also aware of the market capitalization that they assign to a utility (or any other company), which often is different from the book value capital structure. In addition, the formulas developed by world-renowned academics that have won Nobel prizes contain no more unrealistic assumptions than any other of the models (such as, DCF or CAPM) that are used to measure the cost of equity. Finally, I have used the proxy group's (i.e., the Electric Group in this case) book value capital structure for consistency purposes. Since Kentucky Power is a more highly leveraged company, had I used the Company's book value capital structure, my adjustment would have been higher. Instead, I have taken a conservative approach to the leverage adjustment.

Q: What are the implications of a DCF derived return that is related to market value when the results are applied to the book value of a utility's capitalization?

A: The capital structure ratios measured at the utility's book value show more financial leverage, and hence higher risk, than the capitalization measured at their market values. Please refer to Appendix E for the comparison. This means that a market-derived cost of equity, using models such as DCF and CAPM, reflects a level of financial risk that is different from that shown by the book value capitalization. Hence, it is necessary to adjust the market-determined cost of equity upward to reflect the higher financial risk related to the book value capitalization used for ratesetting purposes. Failure to make this modification would result in a mismatch of the lower financial risk related to market value used to measure the cost of equity and the higher financial risk of the book value capital structure used in the ratesetting process. That is to say, the cost of equity for the Electric Group that is related to the 50.07% common equity ratio using book value has higher financial risk than the 62.51% common equity ratio using market values. Because the ratesetting process utilizes the book value capitalization, it is necessary to adjust the market-determined cost of equity for the higher financial risk related to the book value of the capitalization.

Q: How is the DCF-determined cost of equity adjusted for the financial risk associated with the book value of the capitalization?

A: In pioneering work, Nobel laureates Modigliani and Miller ("MM") developed several theories about the role of leverage in a firm's capital structure. As part of that work, Modigliani and Miller established that as the borrowing of a firm increases, the expected return on stockholders' equity also increases. This principle is incorporated into my leverage adjustment which recognizes that the expected return on equity increases to reflect the increased risk associated with the higher financial leverage shown by the book value capital structure, as compared to the market value capital structure that contains lower financial risk. Modigliani and Miller proposed several approaches to quantify the equity return associated with various degrees of debt leverage in a firm's capital structure. These formulas point toward an increase in the equity return associated with the higher financial risk of the book value capital structure. As detailed in Appendix E, the Modigliani and Miller theory shows that the cost of equity increases by 0.74% (10.32% - 9.58%) when the book value of equity, rather than the market value of equity, is used for ratesetting purposes.

Q: Please provide the DCF return based upon your preceding discussion of dividend yield, growth, and leverage.

A: As explained previously, I have utilized a six-month average dividend yield ("D_1 /P_0") adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate ("*g* ") previously developed. The DCF also includes the leverage modification ("*lev.*") required when the book value equity ratio is used in determining the weighted average cost of capital in the ratesetting process rather than the market value equity ratio related to the price of stock. The cost of equity must also include an adjustment to cover flotation costs ("*flot.*"). Therefore, a flotation costs adjustment must be applied to the DCF result (i.e., "*k*") that provides an additional increment to the rate of return on equity (i.e., "*K*"). The factor used to develop the modification that would account for the flotation costs adjustment is provided in Schedule 8 and Appendix F.

A flotation cost allowance is amply supported for Kentucky Power in this case. On June 5, 2002, AEP offered for sale 16 million new shares of common stock at a price of $40.90 per share and 6 million equity units at a price of $50.00 per unit. AEP had previously announced the equity offer on May 17, 2002. The equity units consist of an unsecured senior note and a contract to purchase AEP common stock in the future. Total annual distributions on the equity units will be at the rate of 9.25 percent, consisting of interest on the unsecured note and payments under the contract. The contract requires the investor to purchase AEP common stock for $50 per share on August 16, 2005. For these issues, the flotation costs were represented by 3.06% for the 16 million new shares of common stock and 3.21% for the equity units. Another issue of common stock took place on February 27, 2003. In this offering, AEP sold 56.158 million common shares at $20.95 per share. The flotation costs for this issue were 3.05%.

The resulting DCF cost rate is:

$$D_1/P_0 \quad + \quad g \quad + \quad lev. \quad = \quad k \quad x \quad flot. \quad = \quad K$$

$$4.08\% \quad + \quad 5.50\% \quad + \quad 0.74\% \quad = \quad 10.32\% \quad \text{x} \quad 1.02 \quad = \quad 10.53\%$$

As indicated by the DCF result shown above, the flotation cost adjustment adds 0.21% (10.53% - 10.32%) to the rate of return on common equity for the Electric Group. I have used a flotation cost adjustment factor of 1.02, which is conservative given the experience of AEP noted above and the 3.3% flotation cost factor that is detailed in Appendix F (see page F-2). In my opinion, this adjustment is reasonable for reasons explained in Appendix F. The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant growth assumption. I should reiterate, however, that the DCF indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market because price-earnings multiples do not remain constant.

ALTERNATIVE FORM OF THE DCF MODEL

Q: Have you also calculated the DCF return for your Electric Group following the sustainable growth rate model?

A: Yes. I have provided those results on Schedule 9. Page 1 of that schedule shows the DCF calculations for each company in the Electric Group following generally the procedure set forth by the Federal Energy Regulatory Commission ("FERC") in Opinion No. 445 (92FERC¶61,070). There, the FERC calculated individual DCF returns for each company in the proxy group. For my Electric Group, the range of DCF returns is 8.08% to 13.75%, as shown on page 1 of Schedule 9. The midpoint of this range is 10.92%, and represents the DCF return following the FERC's procedure noted above, and confirmed in Opinion 456 (98FERC¶61,333). In those decisions, the FERC employed the midpoint of the range for setting the rate of return on common equity for electric utilities. These results must also be adjusted for financial leverage differences and for flotation costs.

Q: Generally, what data sources have you used to calculate the DCF return following the FERC's sustainable DCF model?

A: I relied upon the monthly issues of Standard & Poor's Security Owner's Stock Guide for the dividend yield components - - prices and dividends, the most recent issues of The Value Line Investment Survey for the components of the "br+sv" growth rate, and the internet for the IBES/First Call growth rates.

Q: What variables have you used in the sustainable growth rate form of the DCF?

A: On page 2 of Schedule 9, I calculated monthly high and monthly low dividend yields for the most recent six-month period. On page 3 of Schedule 9, I calculated the retention growth rate from the Value Line forecast return on equity (adjusted for average book values) and the retention ratio that is the complement of the dividend payout ratio (see page 4 of Schedule 9) that is calculated from the Value Line forecast earning per share and dividends per share. These input represent the "b times r" growth component, i.e., "b" = the fraction of earnings retained and "r" = the expected rate of return on book common equity.

On page 3 of Schedule 9, the external financing growth rate ("s times v") is calculated with the Value Line forecasts and the current market-to-book ratio for each company. Here, "s" = the new common shares expected to be issued by each company, and "v" = the value that accrues to existing shareholders from selling stock at a price different from book value.

I previously described the role that the IBES/First Call data plays in the DCF model and will not repeat that discussion here.

Q: What is the result of the application of the sustainable growth rate form DCF model?

A: The DCF return for the Electric Group is 10.92%. That result is shown on page 1 of Schedule 9 and has not been modified for application to a book value capital structure, and there is no adjustment for flotation costs.

Q: What are the results of the sustainable growth rate form of the DCF model when modified accordingly?

A: As with the traditional form of the DCF, the difference between the financial leverage measured with the market capitalization and the book value capitalization must be reflected in the result. Flotation costs must also be recognized. The overall results therefore would be:

Yield plus Growth	+	*lev.*	=	*k*	+	*flot.*	=	*K*
10.92%	+	0.99%	=	11.91%	+	0.21%	=	12.12%

The "Yield plus Growth" results for the Electric Group is provided on page 1 of Schedule 9, the leverage adjustment is provided in Appendix E, and the flotation cost adjustment was described previously.

DCF RESULT

Q: What DCF result have you included in your cost of equity analysis?

A: As described previously, there are many forms of the DCF model that can produce widely varying results. In this case, I have presented the results of the traditional DCF model, as well as the model employed by the FERC for electric utilities. In order to bring balance to the DCF model inputs, I propose to employ an average 11.33% (10.53% + 12.12% = 22.65% ÷ 2) of both forms of the model.

RISK PREMIUM ANALYSIS

Q: Please describe your use of the Risk Premium approach to determine the cost of equity.

A: The details of my use of the Risk Premium approach and the evidence in support of my conclusions are set forth in Appendix H. I will summarize them here. With this method, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital.

Q: What long-term public utility debt cost rate did you use in your risk premium analysis?

A: In my opinion, a 6.50% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds. As I will subsequently show, the Moody's index and the Blue Chip forecasts support this figure.

The historical yields for long-term public utility debt are shown graphically on page 1 of Schedule 10. For the twelve months ended June 2005, the average monthly yield on Moody's A-rated index of public utility bonds was 5.83%. For the six and three-month periods ending June 2005, the yields were 5.63% and 5.52%, respectively.

Q: What are the implications of emphasizing recent data taken from a period of relatively low interest rates?

A: When interest rates rise from their current low levels, the overall cost of capital and cost of equity determined from recent data will understate future capital costs. Although it is always possible that interest rates could move lower, this possibility is out-weighed by the prospect of higher future interest rates. That is to say, there is more potential for higher rather than lower interest rates when the beginning point in the process contains low interest rates.

The low interest rates in 2003-'04 were, in part, the product of the Federal Open Market Committee ("FOMC") policy, which is now in transition. Indeed, on June 30, 2004, August 10, 2004, September 21, 2004, November 10, 2004, December 14, 2004, February 2, 2005, March 22, 2005, May 3, 2005, June 30, 2005, and August 9, 2005, the FOMC increased the Fed Funds rate in ten 25 basis point (i.e., 0.25%) increments. These policy actions are widely interpreted as part of the process of moving toward a more neutral range for the Fed Funds rate. Indeed, one of the Fed Governors who serves on the FOMC has indicated that the neutral range for the Fed Funds rate is likely to be in the 3% to 5% range. With a current Fed Funds rate of 3.50%, there are likely to be more increases in the future.

Q: What forecasts of interest rates have you considered in your analysis?

A: I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe above and in Appendix G. The Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on 20-year Treasury bonds published on July 1, 2005 and the yield spread of 1.00% that I describe in Appendix G. For comparative purposes, I have also shown the Blue Chip of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		20-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2005	Third	5.4%	6.2%	4.7%	1.0%	5.7%
2005	Fourth	5.7%	6.5%	4.9%	1.0%	5.9%
2006	First	5.9%	6.7%	5.1%	1.0%	6.1%
2006	Second	6.0%	6.8%	5.2%	1.0%	6.2%
2006	Third	6.1%	6.9%	5.3%	1.0%	6.3%
2006	Fourth	6.1%	7.0%	5.3%	1.0%	6.3%

Q: Are there additional forecasts of interest rates that extend beyond those shown above?

A: Yes. Twice yearly, Blue Chip provides long-term forecast of interest rates. In its June 1, 2005 publication, the Blue Chip published forecasts of interest rates are reported to be:

	Blue Chip Financial Forecasts				
	Corporate		20-Year	A-rated Public Utility	
Year	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2007	6.6%	7.3%	5.9%	1.0%	6.9%
2008	6.5%	7.3%	5.8%	1.0%	6.8%
2009	6.5%	7.3%	5.7%	1.0%	6.7%
2010	6.4%	7.2%	5.6%	1.0%	6.6%
2011	6.5%	7.2%	5.6%	1.0%	6.6%
Averages					
2007-11	6.5%	7.2%	5.7%	1.0%	6.7%
2012-16	6.5%	7.3%	5.8%	1.0%	6.8%

These forecasts show that interest rates will likely be well above current levels. Due to the transition now taking place in the credit markets, emphasis on forecast interest rates is especially appropriate at this time. Indeed, on August 9, 2005, the FOMC yet again raised the Fed Funds rate. The relevance of the forecasts shown above rests upon the prospective nature of the ratesetting process. Given these forecasts and the historical long-term interest rates, a 6.50% yield on A-rated public utility bonds represents a reasonable expectation, especially with the widespread forecasts of higher interest rates covering the years 2007 through 2011.

Q: What equity risk premium have you determined for public utilities?

A: Appendix H provides a discussion of the financial returns that I relied upon to develop the appropriate equity risk premium for the S&P Public Utilities. I have calculated the equity risk premium by comparing the market returns on utility stocks and the market returns on utility bonds. I chose the S&P Public Utility index for the purpose of measuring the market returns for utility stocks because it is intended to represent firms engaged in regulated activities and today is comprised of electric companies and gas companies. The S&P Public Utility index is more closely aligned with these groups than some broader market indexes, such as the S&P 500 Composite index. The S&P Public Utility index is a subset of the overall S&P 500 Composite index. Use of the S&P Public Utility index reduces the role of judgment in establishing the risk premium for public utilities. With the equity risk premiums developed for the S&P Public Utilities as a base, I derived the equity risk premium for the Electric Group.

Q: What equity risk premium for the S&P public utilities have you determined for this case?

A: To develop an appropriate risk premium, I analyzed the results for the S&P Public

Utilities by averaging (i) the midpoint of the range shown by the geometric mean and median and (ii) the arithmetic mean. This procedure has been employed to provide a comprehensive way of measuring the central tendency of the historical returns. As shown by the values set forth on page 2 of Schedule 11 the indicated risk premiums for the various time periods analyzed are 4.99% (1928-2004), 5.75% (1952-2004), 4.85% (1974-2004), and 4.91% (1979-2004). The selection of the shorter periods taken from the entire historical series is designed to provide a risk premium that conforms more nearly to present investment fundamentals and removes some of the more distant data from the analysis.

Q: Do you have further support for the selection of the time periods used in your equity risk premium determination?

A: Yes. First, the terminal year of my analysis presented in Schedule 11 represents the returns realized through 2004. Second, the selection of the initial year of each period was based upon the events that I described in Appendix H. These events were fixed in history and cannot be manipulated as later financial data becomes available. That is to say, using the Treasury-Federal Reserve Accord as a defining event, the year 1952 is fixed as the beginning point for the measurement period regardless of the financial results that subsequently occurred. Likewise, 1974 represented a benchmark year because it followed the 1973 Arab Oil embargo. Also, the year 1979 was chosen because it began the deregulation of the financial markets. As such, additional data are merely added to the earlier results when they become available, clearly showing that the periods chosen were not driven by the desired results of the study.

Q: What conclusions have you drawn from these data?

A: Using the summary values provided on page 2 of Schedule 11, the 1974-2004 period provides the lowest indicated risk premium, while the 1952-2004 period provides the highest risk premium for the S&P Public Utilities. Within these bounds, a common equity risk premium of 4.95% (4.99% + 4.91% = 9.90% ÷ 2) is shown from data covering the periods 1928-2004 and 1979-2004. Therefore, 4.95% represents a reasonable risk premium for the S&P Public Utilities in this case. As noted earlier in my fundamental risk analysis, differences in risk characteristics must be taken into account when applying the results for the S&P Public Utilities to the Electric Group. I recognized these differences in the development of the equity risk premium in this case. I previously enumerated various differences in fundamentals between the Electric Group and the S&P Public Utilities, including size, market ratios, common equity ratio, return on book equity, operating ratios, coverage, quality of earnings, internally generated funds, and betas. In my opinion, these differences indicate that 4.75% represents a reasonable common equity risk premium in this case. This represents approximately 96% (4.75% ÷ 4.95% = 0.96) of the risk premium of the S&P Public Utilities and is reflective of the risk of the Electric Group compared to the S&P Public Utilities.

Q: What common equity cost rate would be appropriate using this equity risk premium and the yield on long-term public utility debt?

A: The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i") and the equity risk premium (i.e., "RP"). To that cost must be added an adjustment for common stock financing costs ("flot.").

The Risk Premium approach provides a cost of equity of:

$$i \quad + \quad RP \quad = \quad k \quad + \quad flot. \quad = \quad K$$

$$6.50\% \quad + \quad 4.75\% \quad = \quad 11.25\% \quad + \quad 0.21\% \quad = \quad 11.46\%$$

CAPITAL ASSET PRICING MODEL

Q: How have you used the Capital Asset Pricing Model to measure the cost of equity in this case?

A: I have used the Capital Asset Pricing Model ("CAPM") in addition to my other methods. As with other models of the cost of equity, the CAPM contains a variety of assumptions that I discuss in Appendix I. Therefore, this method should be used with other methods to measure the cost of equity, as each will complement the other and will provide a result that will alleviate the unavoidable shortcomings found in each method.

Q: What are the features of the CAPM as you have used it?

A: The CAPM uses the yield on a risk-free interest bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. The details of my use of the CAPM and evidence in support of my conclusions are set forth in Appendix I. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities. As such, to calculate the CAPM it is necessary to employ firms with traded stocks. In this regard, I performed a CAPM calculation for the Electric Group. In contrast, my Risk Premium approach also considers industry- and company-specific factors because it is not limited to measuring just systematic risk. As a consequence, the Risk Premium approach is more comprehensive than the CAPM. In addition, the Risk Premium approach provides a better measure of the cost of equity because it is founded upon the yields on corporate bonds rather than Treasury bonds.

Q: What betas have you considered in the CAPM?

A: For my CAPM analysis, I initially considered the Value Line betas. As shown on page 1 of Schedule 12, the average beta is .72 for the Electric Group.

Q: What betas have you used in the CAPM determined cost of equity?

A: The betas must be reflective of the financial risk associated with the ratesetting capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM unless those betas are applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book value capital structure, the Value Line betas have been unleveraged and releveraged for the common equity ratios using book values. This adjustment has been made with the formula:

$$\beta l = \beta u\,[1 + (1 - t)\,D/E + P/E]$$

where βl = the leveraged beta, βu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and therefore are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at their market values, the beta would become .52 for the Electric Group if it employed no leverage and was 100% equity financed. With the unleveraged beta as a base, I calculated the leveraged beta of .86 for the Electric Group associated with book value capital structure.

Q: What risk-free rate have you used in the CAPM?

A: For reasons explained in Appendix G, I have employed the yields on 20-year Treasury bonds using both historical and forecast data to match the longer-term horizon associated with the ratesetting process. As shown on pages 2 and 3 of Schedule 12, I provided the historical yields on 20-year Treasury bonds. For the twelve months ended June 2005, the average yield was 4.81%, as shown on page 3 of that schedule. For the six- and three-months ended June 2005, the yields on 20-year Treasury bonds were 4.66% and 4.55%, respectively. As shown on page 4 of Schedule 11, forecasts published by Blue Chip on July 1, 2005 indicate that the yields on long-term Treasury bonds are expected to increase to 5.3% during the next six quarters. The longer term forecasts described previously show that the yields on Treasury bonds will average 5.7% from 2007 through 2011. For reasons explained previously, forecasts of interest rates should be emphasized at this time. Hence, I have used a 5.50% risk-free rate of return for CAPM purposes.

Q: What market premium have you used in the CAPM?

A: As developed in Appendix I, the market premium is developed by averaging historical market performance (i.e., 6.6%) and the forecasts (i.e., 6.89%). The resulting market premium is 6.75% (6.6% + 6.89% = 13.49% ÷ 2), which represents the average market premium using historical and forecast data.

Q: What CAPM result have you determined using the CAPM?

A: Using the 5.50% risk-free rate of return, the leverage adjusted beta of .86 for the Electric Group, the 6.75% market premium, and the flotation cost adjustment developed previously, the following result is indicated.

$$Rf \quad + \quad \beta \quad (Rm\text{-}Rf) \quad = \quad k \quad + \quad flot. \quad = \quad K$$

$$5.50\% + .86 \quad (6.75\%) \quad = \quad 11.31\% \quad + \quad 0.21\% \quad = \quad 11.52\%$$

COMPARABLE EARNINGS APPROACH

Q: How have you applied the Comparable Earnings approach in this case?

A: The technical aspects of my Comparable Earnings approach are set forth in Appendix J. In order to identify the appropriate return on equity for a public utility, it is necessary to analyze returns experienced by other firms within the context of the Comparable Earnings standard. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided. To avoid circularity, it is essential that returns achieved under regulation not provide the basis for a regulated return. Because regulated firms must compete with non-regulated firms in the capital markets, it is appropriate to view the returns experienced by firms which operate in competitive markets. One must keep in mind that the rates of return for non-regulated firms represent results on book value actually achieved, or expected to be achieved, because the starting point of the calculation is the actual experience of companies that are not subject to rate regulation. The United States Supreme Court has held that:

> "[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

Therefore, it is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

There are two avenues available to implement the Comparable Earnings approach. One method would involve the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry would serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms. As such, this approach to Comparable Earnings avoids the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. Rather, it provides an indication of an earnings rate derived from non-regulated companies that are subject to competition in the marketplace and not rate regulation. Because, regulation is a substitute for competitively-determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into a fair rate of return. This is because returns realized by non-regulated firms have become increasingly relevant with the current risk profile of the public utility business. Moreover, the rate of return for a regulated public utility must be competitive with returns available on investments in other enterprises having corresponding risks, especially in a more global economy.

To identify the comparable risk companies, the Value Line Investment Survey for Windows was used to screen for firms of comparable risks. The Value Line Investment Survey for Windows includes data on approximately 1700 firms. Excluded from the selection process were companies incorporated in foreign countries and master limited partnerships (MLPs).

Q: How have you implemented the Comparable Earnings approach?

A: In order to implement the Comparable Earnings approach, non-regulated companies were selected from the Value Line Investment Survey for Windows that have six categories (see Appendix J for definitions) of comparability designed to reflect the risk of the Electric Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Electric Group. The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The identities of companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on page 1 of Schedule 13.

Value Line data was relied upon because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Schedule 13 because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Finally, because many of the comparability factors, as well as the published returns, are used by investors for selecting stocks, and to the extent that investors rely on the Value Line service to gauge their returns, it is, therefore, an appropriate database for measuring comparable return opportunities.

Q: What data have you used in your Comparable Earnings analysis?

A: I have used both historical realized returns and forecast returns for non-utility companies. As noted previously, I have not used returns for utility companies so as to avoid the circularity that arises from using regulatory influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (5 historical years and 5 projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization because the nature of the analysis relates to book value. Hence, Comparable Earnings does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. The historical rate of return on book common equity was 14.1% using the median value as shown on page 2 of Schedule 13. The forecast rates of return as published by Value Line are shown by the 13.0% median values also provided on page 2 of Schedule 13.

Q: What rate of return on common equity have you determined in this case using the Comparable Earnings approach?

A: The average of the historical and forecast median rates of return is 13.55% (14.1% + 13.0% = 27.1% ÷ 2) and represents the Comparable Earnings result for this case.

CREDIT QUALITY AND CONCLUSION

Q: What are some of the important factors that influence credit quality?

A: The Company must have the financial strength that will, at a minimum, permit it to maintain a financial profile that is commensurate with the requirements to obtain a solid investment grade bond rating. Strong credit quality is necessary to provide a utility with the highest degree of financial flexibility in order to attract capital on reasonable terms during all economic conditions. Customers also benefit from strong credit quality because the utility will be able to obtain lower financing costs that are passed on to customers in the form of a lower embedded cost of debt. For this reason, rates should be established that would allow the maintenance of a financial profile that would support a strong A-bond rating.

Q: What credit quality matrix is now being emphasized by the credit rating agencies?

A: On June 2, 2004, S&P revised its financial guidelines for assessing the credit quality of the utility industry. Aside from the qualitative factors that influence a credit quality rating, there are now three financial guidelines with published benchmarks. S&P has ceased publishing benchmark criteria for pre-tax interest coverage. Interest coverage provided by funds from operations ("FFO") is presently emphasized by S&P in its quantitative analysis. As such, FFO interest coverage is now the benchmark used to assess the credit quality profile for public utilities. The FFO/interest coverage associated with an A credit quality profile should be the focus.

Q: What is your conclusion concerning the Company's cost of equity?

A: Based upon the application of a variety of methods and models described previously, it is my opinion that the reasonable rate of return on common equity is 11.50% for the Company. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method. I have based my recommendation upon the results of the methods/models applied with data for the Electric Group. In conclusion, the Company should be allowed a 11.50% rate of return on common equity, so they can compete in the capital markets, attain reasonable credit quality, and be adequately compensated for their business risk.

Q: Does this conclude your prepared direct testimony?

A: Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

STATE OF NEW JERSEY

CASE NO. 2005-000341

COUNTY OF CAMDEN

AFFIDAVIT

Paul R. Moul, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Paul R. Moul

Paul R. Moul

Subscribed and sworn to before me by Paul R. Moul this 20th day of September, 2005.

Ruby Marie Tucker

Notary Public

My Commission Expires 5/12/09

Notary Public of New Jersey
I.D.#2165661 Com.Exp. 5/12/09
Ruby Marie Tucker

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY CASE NO. 2005-000341

APPENDICES A THROUGH J

TO ACCOMPANY THE

DIRECT TESTIMONY

OF

PAUL R. MOUL

September 26, 2005

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past twenty-nine years, I have continuously studied the rate of return requirements for cost of service regulated firms. In this regard, I have supervised the preparation of rate of return studies which were employed in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty (30) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Oklahoma, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, and West Virginia; and the Philadelphia Gas Commission. My testimony has been offered in over 200 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000).

Further, I have been the consultant to the New York Chapter of the National Association of Water Companies which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000).

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

I am a member of the Society of Utility and Regulatory Financial Analysis (formerly the National Society of Rate of Return Analysts) and have attended several Financial Forums sponsored by the Society. I attended the first National Regulatory Conference at the Marshall-Wythe School of Law, College of William and Mary. I also attended an Executive Seminar sponsored by the Colgate Darden Graduate Business School of the University of Virginia concerning Regulated Utility Cost of Equity and the Capital Asset Pricing Model. In October 1984, I attended a Standard & Poor's Seminar on the Approach to Municipal Utility Ratings, and in May 1985, I attended an S&P Seminar on Telecommunications Ratings.

My lecture and speaking engagements include:

Date	Occasion	Sponsor
April 2001	Thirty-third Financial Forum	Society of Utility & Regulatory Financial Analysts
December 2000	Pennsylvania Public Utility Law Conference: Non-traditional Players in the Water Industry	Pennsylvania Bar Institute
July 2000	EEI Member Workshop Developing Incentives Rates: Application and Problems	Edison Electric Institute
February 2000	The Sixth Annual FERC Briefing	Exnet and Bruder, Gentile & Marcoux, LLP
March 1994	Seventh Annual Proceeding	Electric Utility Business Environment Conf.
May 1993	Financial School	New England Gas Assoc.
April 1993	Twenty-Fifth Financial Forum	National Society of Rate of Return Analysts
June 1992	Rate and Charges Subcommittee Annual Conference	American Water Works Association
May 1992	Rates School	New England Gas Assoc.
October 1989	Seventeenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners Florida Public Service Commission and University of Utah
October 1988	Sixteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah

May 1988	Twentieth Financial Forum	National Society of Rate of Return Analysts
October 1987	Fifteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah
September 1987	Rate Committee Meeting	American Gas Association
May 1987	Pennsylvania Chapter annual meeting	National Association of Water Companies
October 1986	Eighteenth Financial Forum	National Society of Rate of Return
October 1984	Fifth National on Utility Ratemaking Fundamentals	American Bar Association
March 1984	Management Seminar	New York State Telephone Association
February 1983	The Cost of Capital Seminar	Temple University, School of Business Admin.
May 1982	A Seminar on Regulation and The Cost of Capital	New Mexico State University, Center for Business Research and Services
October 1979	Economics of Regulation	Brown University

APPENDIX B TO DIRECT TESTIMONY OF PAUL R. MOUL

RATESETTING PRINCIPLES

Under traditional cost of service regulation, an agency engaged in ratesetting, such as the Commission, serves as a substitute for competition. In setting rates, a regulatory agency must carefully consider the public's interest in reasonably priced, as well as safe and reliable, service. The level of rates must also provide an opportunity to earn a rate of return for the public utility and its investors that is commensurate with the risk to which the invested capital is exposed so that the public utility has access to the capital required to meet its service responsibilities to its customers. Without an opportunity to earn a fair rate of return, a public utility will be unable to attract sufficient capital required to meet its responsibilities over time.

It is important to remember that regulated firms must compete for capital in a global market with non-regulated firms, as well as municipal, state and federal governments. Traditionally, a public utility has been responsible for providing a particular type of service to its customers within a specific market area. Although this relationship with its customers has been changing, it remains quite different from a non-regulated firm which is free to enter and exit competitive markets in accordance with available business opportunities.

As established by the landmark Bluefield and Hope cases,[1] several tests must be satisfied to demonstrate the fairness or reasonableness of the rate of return. These tests include a determination of whether the rate of return is (i) similar to that of other financially sound businesses having similar or comparable risks, (ii) sufficient to ensure confidence in the financial integrity of the public utility, and (iii) adequate to maintain and support the credit of the utility, thereby enabling it to attract, on a reasonable cost basis, the funds necessary to

[1] Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

satisfy its capital requirements so that it can meet the obligation to provide adequate and reliable service to the public.

A fair rate of return must not only provide the utility with the ability to attract new capital, it must also be fair to existing investors. An appropriate rate of return which may have been reasonable at one point in time may become too high or too low at a subsequent point in time, based upon changing business risks, economic conditions and alternative investment opportunities. When applying the standards of a fair rate of return, it must be recognized that the end result must provide for the payment of interest on the company's debt, the payment of dividends on the company's stock, the recovery of costs associated with securing capital, the maintenance of reasonable credit quality for the company, and support of the company's financial condition, which today would include those measures of financial performance in the areas of interest coverage and adequate cash flow derived from a reasonable level of earnings.

EVALUATION OF RISK

The rate of return required by investors is directly linked to the perceived level of risk. The greater the risk of an investment, the higher is the required rate of return necessary to compensate for that risk all else being equal. Because investors will seek the highest rate of return available, considering the risk involved, the rate of return must at least equal the investor-required, market-determined cost of capital if public utilities are to attract the necessary investment capital on reasonable terms.

In the measurement of the cost of capital, it is necessary to assess the risk of a firm. The level of risk for a firm is often defined as the uncertainty of achieving expected performance, and is sometimes viewed as a probability distribution of possible outcomes. Hence, if the uncertainty of achieving an expected outcome is high, the risk is also high. As a consequence, high risk firms must offer investors higher returns than low risk firms which pay less to attract capital from investors. This is because the level of uncertainty, or risk of not realizing expected returns, establishes the compensation required by investors in the capital markets. Of course, the risk of a firm must also be considered in the context of its ability to actually experience adequate earnings which conform with a fair rate of return. Thus, if there is a high probability that a firm will not perform well due to fundamentally poor market conditions, investors will demand a higher return.

The investment risk of a firm is comprised of its business risk and financial risk. Business risk is all risk other than financial risk, and is sometimes defined as the staying power of the market demand for a firm's product or service and the resulting inherent uncertainty of realizing expected pre-tax returns on the firm's assets. Business risk encompasses all operating factors, e.g., productivity, competition, management ability, etc. that bear upon the expected pre-tax operating income attributed to the fundamental nature of a firm's business. Financial risk results from a firm's use of borrowed funds (or similar sources of capital with fixed payments) in its capital structure, i.e., financial leverage. Thus, if a firm did not employ financial leverage by borrowing any capital, its investment risk would be represented by its business risk.

It is important to note that in evaluating the risk of regulated companies, financial leverage cannot be considered in the same context as it is for non-regulated companies. Financial leverage has a different meaning for regulated firms than for non-regulated companies. For regulated public utilities, the cost of service formula gives the benefits of financial leverage to consumers in the form of lower revenue requirements. For non-regulated companies, all benefits of financial leverage are retained by the common stockholder. Although retaining none of the benefits, regulated firms bear the risk of financial leverage. Therefore, a regulated firm's rate of return on common equity must recognize the greater financial risk shown by the higher leverage typically employed by public utilities.

Although no single index or group of indices can precisely quantify the relative investment risk of a firm, financial analysts use a variety of indicators to assess that risk. For example, the creditworthiness of a firm is revealed by its bond ratings. If the stock is traded, the price-earnings multiple, dividend yield, and beta coefficients (a statistical measure of a stock's relative volatility to the rest of the market) provide some gauge of overall risk. Other indicators, which are reflective of business risk, include the variability of the rate of return on equity, which is indicative of the uncertainty of actually achieving the expected earnings; operating ratios (the percentage of revenues consumed by operating expenses, depreciation, and taxes other than income tax), which are indicative of profitability; the quality of earnings, which considers the degree to which earnings are the product of accounting principles or cost deferrals; and the level of internally generated funds. Similarly, the proportion of senior capital in a company's capitalization is the measure of financial risk which is often analyzed in the context of the equity ratio (i.e., the complement of the debt ratio).

COST OF EQUITY--GENERAL APPROACH

Through a fundamental financial analysis, the relative risk of a firm must be established prior to the determination of its cost of equity. Any rate of return recommendation which lacks such a basis will inevitably fail to provide a utility with a fair rate of return except by coincidence. With a fundamental risk analysis as a foundation, standard financial models can be employed by using informed judgment. The methods which have been employed to measure the cost of equity include: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") approach, the Capital Asset Pricing Model ("CAPM") and the Comparable Earnings ("CE") approach.

The traditional DCF model, while useful in providing some insight into the cost of equity, is not an approach that should be used exclusively. The divergence of stock prices from company-specific fundamentals can provide a misleading cost of equity calculation. As reported in The Wall Street Journal on June 6, 1991, a statistical study published by Goldman Sachs indicated that only 35% of stock price growth in the 1980's could be attributed to earnings and interest rates. Further, 38% of the rise in stock prices during the 1980's was attributed to unknown factors. The Goldman Sachs study highlights the serious limitations of a model, such as DCF, which is founded upon identification of specific variables to explain stock price growth. That is to say, when stock price growth exceeds growth in a company's earnings per share, models such as DCF will misspecify investor expected returns which are comprised of capital gains, as well as dividend receipts. As such, a combination of methods should be used to measure the cost of equity.

The Risk Premium analysis is founded upon the prospective cost of long-term debt, i.e., the yield that the public utility must offer to raise long-term debt capital directly from investors. To that yield must be added a risk premium in recognition of the greater risk of common equity over debt. This additional risk is, of course, attributable to the fact that the payment of interest and principal to creditors has priority over the payment of dividends and return of capital to equity investors. Hence, equity investors require a higher rate of return than the yield on long-term corporate bonds.

The CAPM is a model not unlike the traditional Risk Premium. The CAPM employs the yield on a risk-free interest-bearing obligation plus a premium as compensation for risk. Aside from the reliance on the risk-free rate of return, the CAPM gives specific quantification to systematic (or market) risk as measured by beta.

The Comparable Earnings approach measures the returns expected/experienced by other non-regulated firms and has been used extensively in rate of return analysis for over a half century. However, its popularity diminished in the 1970s and 1980s with the popularization of market-based models. Recently, there has been renewed interest in this approach. Indeed, the financial community has expressed the view that the regulatory process must consider the returns which are being achieved in the non-regulated sector so that public utilities can compete effectively in the capital markets. Indeed, with additional competition being introduced throughout the traditionally regulated public utility industry, returns expected to be realized by non-regulated firms have become increasing relevant in the ratesetting process. The Comparable Earnings approach considers directly those requirements and it fits the established standards for a fair rate of return set forth in the Bluefield and Hope decisions. The Hope decision requires that a fair return for a utility must be equal to that earned by firms of comparable risk.

APPENDIX E TO DIRECT TESTIMONY OF PAUL R. MOUL

DISCOUNTED CASH FLOW ANALYSIS

Discounted Cash Flow ("DCF") theory seeks to explain the value of an economic or financial asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. Thus, if \$100 is to be received in a single payment 10 years subsequent to the acquisition of an asset, and the appropriate risk-related interest rate is 8%, the present value of the asset would be \$46.32 (Value = \$100. $(1.08)^{10}$) arising from the discounted future cash flow. Conversely, knowing the present \$46.32 price of an asset (where price = value), the \$100 future expected cash flow to be received 10 years hence shows an 8% <u>annual</u> rate of return implicit in the price and future cash flows expected to be received.

In its simplest form, the DCF theory considers the number of years from which the cash flow will be derived and the annual compound interest rate which reflects the risk or uncertainty associated with the cash flows. It is appropriate to reiterate that the dollar values to be discounted are future cash flows.

DCF theory is flexible and can be used to estimate value (or price) or the annual required rate of return under a wide variety of conditions. The theory underlying the DCF methodology can be easily illustrated by utilizing the investment horizon associated with a preferred stock not having an annual sinking fund provision. In this case, the investment horizon is infinite, which reflects the perpetuity of a preferred stock. If P represents price, Kp is the required rate of return on a preferred stock, and D is the annual dividend (P and D with time subscripts), the value of a preferred share is equal to the present value of the dividends to be received in the future discounted at the appropriate risk-adjusted interest rate, Kp. In this circumstance:

$$P_0 = \frac{D_1}{(1+Kp)} + \frac{D_2}{(1+Kp)^2} + \frac{D_3}{(1+Kp)^3} + \ldots + \frac{D_n}{(1+Kp)^n}$$

If $D_1 = D_2 = D_3 = \ldots D_n$ as is the case for preferred stock, and n approaches infinity, as is the case for non-callable preferred stock without a sinking fund, then this equation reduces to:

$$P_0 = \frac{D_1}{Kp}$$

This equation can be used to solve for the annual rate of return on a preferred stock when the current price and subsequent annual dividends are known. For example, with D_1 = \$1.00, and P_0 = \$10, then Kp = \$1.00 ÷ \$10, or 10%.

The dividend discount equation, first shown, is the generic DCF valuation model for all equities, both preferred and common. While preferred stock generally pays a constant dividend, permitting the simplification subsequently noted, common stock dividends are not constant. Therefore, absent some other simplifying condition, it is necessary to rely upon the generic form of the DCF. If, however, it is assumed that $D_1, D_2, D_3, \ldots D_n$ are systematically related to one another by a constant growth rate (g), so that $D_0\,(1+g) = D_1$, $D_1\,(1+g) = D_2$, $D_2\,(1+g) = D_3$ and so on approaching infinity, and if Ks (the required rate of return on a common stock) is greater than g, then the DCF equation can be reduced to:

$$P_0 = \frac{D_1}{Ks - g} \quad or \quad P_0 = \frac{D_0(1+g)}{Ks - g}$$

which is the periodic form of the "Gordon" model.[2] Proof of the DCF equation is found in all modern basic finance textbooks. This DCF equation can be easily solved as:

[2] Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in

$$Ks = \frac{D_0(1+g)}{P_0} + g$$

which is the periodic form of the Gordon Model commonly applied in estimating equity rates of return in rate cases. When used for this purpose, *Ks* is the annual rate of return on common equity demanded by investors to induce them to hold a firm's common stock. Therefore, the variables D_0, P_0 and g must be estimated in the context of the market for equities, so that the rate of return, which a public utility is permitted the opportunity to earn, has meaning and reflects the investor-required cost rate.

Application of the Gordon model with market derived variables is straightforward. For example, using the most recent prior annualized dividend (D_0) of \$0.80, the current price (P_0) of \$10.00, and the investor expected dividend growth rate (g) of 5%, the solution of the DCF formula provides a 13.4% rate of return. The dividend yield component in this instance is 8.4%, and the capital gain component is 5%, which together represent the total 13.4% annual rate of return required by investors. The capital gain component of the total return may be calculated with two adjacent future year prices. For example, in the eleventh year of the holding period, the price per share would be \$17.10 as compared with the price per share of \$16.29 in the tenth year which demonstrates the 5% annual capital gain yield.

Some DCF devotees believe that it is more appropriate to estimate the required return on equity with a model which permits the use of multiple growth rates. This may be a plausible approach to DCF, where investors expect different dividend growth rates in the near term and

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the mid-1950's, J. B. Williams exposited the DCF model in its present form nearly two decades earlier.

long run. If two growth rates, one near term and one long-run, are to be used in the context of a price (P_0) of $10.00, a dividend (D_0) of $0.80, a near-term growth rate of 5.5%, and a long-run expected growth rate of 5.0% beginning at year 6, the required rate of return is 13.57% solved with a computer by iteration.

Use of DCF in Ratesetting

The DCF method can provide a misleading measure of the cost of equity in the ratesetting process when stock prices diverge from book values by a meaningful margin. When the difference between share values and book values is significant, the results from the DCF can result in a misspecified cost of equity when those results are applied to book value. This is because investor expected returns, as described by the DCF model, are related to the market value of common stock. This discrepancy is shown by the following example. If it is assumed, hypothetically, that investors require a 12.5% return on their common stock investment value (i.e., the market price per share) when share values represent 150% of book value, investors would require a total annual return of $1.50 per share on a $12.00 market value to realize their expectations. If, however, this 12.5% market-determined cost rate is applied to an original cost rate base which is equivalent to the book value of common stock of $8.00 per share, the utility's actual earnings per share would be only $1.00. This would result in a $.50 per share earnings shortfall which would deny the utility the ability to satisfy investor expectations.

As a consequence, a utility could not withstand these DCF results applied in a rate case and also sustain its financial integrity. This is because $1.00 of earnings per share and a 75% dividend payout ratio would provide earnings retention growth of just 3.125% (i.e., $1.00 x .75 = $0.75, and $1.00 - $0.75 = $0.25 ÷ $8.00 = 3.125%). In this example, the earnings retention growth rate plus the 6.25% dividend yield ($0.75 ÷ $12.00) would equal 9.375% (6.25% +

3.125%) as indicated by the DCF model. This DCF result is the same as the utility's rate of dividend payments on its book value (i.e., \$0.75 ÷ \$8.00 = 9.375%). This situation provides the utility with no earnings cushion for its dividend payment because the DCF result equals the dividend rate on book value (i.e., both rates are 9.375% in the example). Moreover, if the price employed in my example were higher than 150% of book value, a "negative" earnings cushion would develop and cause the need for a dividend reduction because the DCF result would be less than the dividend rate on book value. For these reasons, the usefulness of the DCF method significantly diminishes as market prices and book values diverge.

Further, there is no reason to expect that investors would necessarily value utility stocks equal to their book value. In fact, it is rare that utility stocks trade at book value. Moreover, high market-to-book ratios may be reflective of general market sentiment. Were regulators to use the results of a DCF model, that fails to produce the required return when applied to an original cost rate base, they would penalize a company with high market-to-book ratios. This clearly would penalize a regulated firm and its investors that purchased the stock at its current price. When investor expectations are not fulfilled, the market price per share will decline and a new, different equity cost rate would be indicated from the lower price per share. This condition suggests that the current price would be subject to disequilibrium and would not allow a reasonable calculation of the cost of equity. This situation would also create a serious disincentive for management initiative and efficiency. Within that framework, a perverse set of goals and rewards would result, i.e., a high authorized rate of return in a rate case would be the reward for poor financial performance, while low rates of return would be the reward for good financial performance. As such, the DCF results should not be used alone to determine the cost of equity, but should be used along with other complementary methods.

Dividend Yield

The historical annual dividend yield for the Electric Group is shown on Schedule 3. The 2000-2004 five-year average dividend yield was 4.8% for the Electric Group. The monthly dividend yields for the past twelve months are shown graphically on Schedule 5. These dividend yields reflect an adjustment to the month-end closing prices to remove the pro rata accumulation of the quarterly dividend amount since the last ex-dividend date.

The ex-dividend date usually occurs two business days before the record date of the dividend (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment--usually about two to three weeks prior to the actual payment). During a quarter (here defined as 91 days), the price of a stock moves up ratably by the dividend amount as the ex-dividend date approaches. The stock's price then falls by the amount of the dividend on the ex-dividend date. Therefore, it is necessary to calculate the fraction of the quarterly dividend since the time of the last ex-dividend date and to remove that amount from the price. This adjustment reflects normal recurring pricing of stocks in the market, and establishes a price which will reflect the true yield on a stock.

A six-month average dividend yield has been used to recognize the prospective orientation of the ratesetting process as explained in the direct testimony. For the purpose of a DCF calculation, the average dividend yields must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future rather than the recent dividend payment annualized. An adjustment to the dividend yield component, when computed with annualized dividends, is required based upon investor expectation of quarterly dividend increases.

The procedure to adjust the average dividend yield for the expectation of a dividend increase during the initial investment period will be at a rate of one-half the growth component, developed below. The DCF equation, showing the quarterly dividend payments as D_0, may be stated in this fashion:

$$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$$

The adjustment factor, based upon one-half the expected growth rate developed in my direct testimony, will be 2.750% (5.50% x .5) for the Electric Group, which assumes that two dividend payments will be at the expected higher rate during the initial investment period. Using the six-month average dividend yield as a base, the prospective (forward) dividend yield would be 4.07% (3.96% x 1.02750) for the Electric Group.

Another DCF model that reflects the discrete growth in the quarterly dividend *(D_0)* is as follows:

$$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$$

This procedure confirms the reasonableness of the forward dividend yield previously calculated. The quarterly discrete adjustment provides a dividend yield of 4.10% (3.96% x 1.03415) for the Electric Group. The use of an adjustment is required for the periodic form of the DCF in order to properly recognize that dividends grow on a discrete basis.

In either of the preceding DCF dividend yield adjustments, there is no recognition for the compound returns attributed to the quarterly dividend payments. Investors have the opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the periodic quarterly dividend payments (D_0), results in a third DCF formulation:

$$k = \left[\left(1 + \frac{D_0}{P_0} \right)^4 - 1 \right] + g$$

This DCF equation provides no further recognition of growth in the quarterly dividend. Combining discrete quarterly dividend growth with quarterly compounding would provide the following DCF formulation, stating the quarterly dividend payments (D_0):

$$k = \left[\left(1 + \frac{D_0 (1 + g)^{.25}}{P_0} \right)^4 - 1 \right] + g$$

A compounding of the quarterly dividend yield provides another procedure to recognize the necessity for an adjusted dividend yield. The unadjusted average quarterly dividend yield was 0.9900% (3.96% ÷ 4) for the Electric Group. The compound dividend yield would be 4.07% (1.010033^4-1) for the Electric Group, recognizing quarterly dividend payments in a forward-looking manner. These dividend yields conform with investors' expectations in the context of reinvestment of their cash dividend.

For the Electric Group, a 4.08% forward-looking dividend yield is the average (4.07% + 4.10% + 4.07% = 12.24% ÷ 3) of the adjusted dividend yield using the form $D_0 / P_0 \ (1+.5g)$, the dividend yield recognizing discrete quarterly growth, and the quarterly compound dividend yield with discrete quarterly growth.

Growth Rate

If viewed in its infinite form, the DCF model is represented by the discounted value of an endless stream of growing dividends. It would, however, require 100 years of future dividend payments so that the discounted value of those payments would equate to the present price so that the discount rate and the rate of return shown by the simplified Gordon form of the DCF model would be about the same. A century of dividend receipts represents an unrealistic investment horizon from almost any perspective. Because stocks are not held by investors forever, the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, investor expected returns in the equity market are provided by capital appreciation of the investment as well as receipt of dividends. As such, the sale price of a stock can be viewed as a liquidating dividend which can be discounted along with the annual dividend receipts during the investment holding period to arrive at the investor expected return.

In its constant growth form, the DCF assumes that with a constant return on book common equity and constant dividend payout ratio, a firm's earnings per share, dividends per share and book value per share will grow at the same constant rate, absent any external financing by a firm. Because these constant growth assumptions do not actually prevail in the capital markets, the capital appreciation potential of an equity investment is best measured by the expected growth in earnings per share. Since the traditional form of the DCF assumes no change in the price-earnings multiple, the value of a firm's equity will grow at the same rate as earnings per share. Hence, the capital gains yield is best measured by earnings per share growth using company-specific variables.

Investors consider both historical and projected data in the context of the expected growth rate for a firm. An investor can compute historical growth rates using compound growth rates or growth rate trend lines. Otherwise, an investor can rely upon published growth rates as provided in widely-circulated, influential publications. However, a traditional constant growth DCF analysis that is limited to such inputs suffers from the assumption of no change in the price-earnings multiple, i.e., that the value of a firm's equity will grow at the same rate as earnings. Some of the factors which actually contribute to investors' expectations of earnings growth and which should be considered in assessing those expectations, are: (i) the earnings rate on existing equity, (ii) the portion of earnings not paid out in dividends, (iii) sales of additional common equity, (iv) reacquisition of common stock previously issued, (v) changes in financial leverage, (vi) acquisitions of new business opportunities, (vii) profitable liquidation of assets, and (viii) repositioning of existing assets. The realities of the equity market regarding total return expectations, however, also reflect factors other than these inputs. Therefore, the DCF model contains overly restrictive limitations when the growth component is stated in terms of earnings per share (the basis for the capital gains yield) or dividends per share (the basis for the infinite dividend discount model). In these situations, there is inadequate recognition of the capital gains yields arising from stock price growth which could exceed earnings or dividends growth.

To assess the growth component of the DCF, analysts' projections of future growth influence investor expectations as explained above. One influential publication is The Value Line Investment Survey which contains estimated future projections of growth. The Value Line Investment Survey provides growth estimates which are stated within a common economic environment for the purpose of measuring relative growth potential. The basis for these projections is the Value Line 3 to 5 year hypothetical economy. The Value Line hypothetical economic environment is represented by components and subcomponents of the National Income Accounts which reflect in the aggregate assumptions concerning the unemployment rate, manpower productivity, price inflation, corporate income tax rate, high-grade corporate bond interest rates, and Fed policies. Individual estimates begin with the correlation of sales, earnings and dividends of a company to appropriate components or subcomponents of the future National Income Accounts. These calculations provide a consistent basis for the published forecasts. Value Line's evaluation of a specific company's future prospects are considered in the context of specific operating characteristics that influence the published projections. Of particular importance for regulated firms, Value Line considers the regulatory quality, rates of return recently authorized, the historic ability of the firm to actually experience the authorized rates of return, the firm's budgeted capital spending, the firm's financing forecast, and the dividend payout ratio. The wide circulation of this source and frequent reference to Value Line in financial circles indicate that this publication has an influence on investor judgment with regard to expectations for the future.

There are other sources of earnings growth forecasts. One of these sources is the Institutional Brokers Estimate System ("IBES"). The IBES service provides data on consensus earnings per share forecasts and five-year earnings growth rate estimates. The publisher of IBES has been purchased by Thomson/First Call. The IBES forecasts have been integrated into the First Call consensus growth forecasts. The earnings estimates are obtained from financial analysts at brokerage research departments and from institutions whose securities analysts are projecting earnings for companies in the First Call universe of companies. Other services that tabulate earnings forecasts and publish them are Zacks Investment Research and Market Guide (which is provided over the Internet by Reuters). As with the IBES/First Call forecasts, Zacks and Reuters/Market Guide provide consensus forecasts collected from analysts for most publically traded companies.

In each of these publications, forecasts of earnings per share for the current and subsequent year receive prominent coverage. That is to say, IBES/First Call, Zacks, Reuters/Market Guide, and Value Line show estimates of current-year earnings and projections for the next year. While the DCF model typically focusses upon long-run estimates of growth, stock prices are clearly influenced by current and near-term earnings prospects. Therefore, the near-term earnings per share growth rates should also be factored into a growth rate determination.

Although forecasts of future performance are investor influencing[3], equity investors may also rely upon the observations of past performance. Investors' expectations of future growth rates may be determined, in part, by an analysis of historical growth rates. It is apparent that any serious investor would advise himself/herself of historical performance prior to taking an investment position in a firm. Earnings per share and dividends per share represent the principal financial variables which influence investor growth expectations.

Other financial variables are sometimes considered in rate case proceedings. For example, a company's internal growth rate, derived from the return rate on book common equity and the related retention ratio, is sometimes considered. This growth rate measure is represented by the Value Line forecast "BxR" shown on Schedule 7 Internal growth rates are often used as a proxy for book value growth. Unfortunately, this measure of growth is often not reflective of investor-expected growth. This is especially important when there is an

[3] As shown in a National Bureau of Economic Research monograph by John G. Cragg and Burton G. Malkiel, Expectations and the Structure of Share Prices, University of Chicago Press 1982.

indication of a prospective change in dividend payout ratio, earned return on book common equity, change in market-to-book ratios or other fundamental changes in the character of the business. Nevertheless, I have also shown the historical and projected growth rates in book value per share and internal growth rates.

Leverage Adjustment

As noted previously, the divergence of stock prices from book values creates a conflict within the DCF model when the results of a market-derived cost of equity are applied to the common equity account measured at book value in the ratesetting context. This is the situation today where the market price of stock exceeds its book value for most companies. This divergence of price and book value also creates a financial risk difference, whereby the capitalization of a utility measured at its market value contains relatively less debt and more equity than the capitalization measured at its book value. It is a well-accepted fact of financial theory that a relatively higher proportion of equity in the capitalization has less financial risk than another capital structure more heavily weighted with debt. This is the situation for the Electric Group where the market value of its capitalization contains more equity than is shown by the book capitalization. The following comparison demonstrates this situation where the market capitalization is developed by taking the "Fair Value of Financial Instruments" (Disclosures about Fair Value of Financial Instruments -- Statement of Financial Accounting Standards ("FAS") No. 107) as shown in the annual report for these companies and the market value of the common equity using the price of stock. The comparison of capital structure ratios is:

Electric Group	Capitalization at Market Value (Fair Value)	Capitalization at Book Value (Carrying Amounts)
Long-term Debt	36.89%	49.02%
Preferred Stock	0.60	0.90
Common Equity	62.51	50.07
Total	100.00%	100.00%

With regard to the capital structure ratios represented by the carrying amounts shown above, there are some variances from the ratios shown on Schedule 3. These variances arise from the use of balance sheet values in computing the capital structure ratios shown on Schedule 3 and the use of the Carrying Amounts of the Financial Instruments according to FAS 107 (the Carrying Amounts were used in the table shown above to be comparable to the Fair Value amounts used in the comparison calculations).

With the capital ratios calculated above, is necessary to first calculate the cost of equity for a firm without any leverage. The cost of equity for an unleveraged firm using the capital structure ratios calculated with market values is:

$$ku = ke - (((ku - i)\ 1\text{-}t)\ D / E) - (ku - d)\ P / E$$

$$8.47\% = 9.58\% - (((8.47\%-5.63\%)\ .65)\ 36.89\%/62.51\%) - (8.47\% - 6.24\%)\ 0.60\%/62.51\%$$

where ku = cost of equity for an all-equity firm, ke = market determined cost equity, i = cost of debt[4], d = dividend rate on preferred stock[5], D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The formula shown above indicates that the cost of equity for a firm with 100% equity is 8.47% using the market value of the Electric Group's capitalization. Having determined that the cost of equity is 8.47% for a firm with 100% equity, the rate of return on

[4] The cost of debt is the six-month average yield on Moody's A rated public utility bonds.

[5] The cost of preferred is the six-month average yield on Moody's "a" rated preferred stock.

common equity associated with the book value capital structure is:

$$ke = ku + (((ku - i)\ 1\text{-}t)\ D / E) + (ku - d)\ P / E$$

$$10.32\% = 8.47\% + (((8.47\%\text{-}5.63\%).65)\ 49.02\%/50.07\%) + (8.47\%\text{-}6.24\%)\ 0.90\%/50.07\%$$

Following the same procedure with the indicated results of the FERC model, the leverage adjustment would be:

$$ku = ke - (((ku - i)\ 1\text{-}t)\ D / E) - (ku - d)\ P / E$$

$$9.43\% = 10.92\% - (((9.43\%\text{-}5.63\%).65)\ 36.89\%/62.51\%) - (9.43\% - 6.24\%)\ 0.60\%/62.51\%$$

$$ke = ku + (((ku - i)\ 1\text{-}t)\ D / E) + (ku - d)\ P / E$$

$$11.91\% = 9.43\% + (((9.43\%\text{-}5.63\%).65)\ 49.02\%/50.07\%) + (9.43\% - 6.24\%)\ 0.90\%/50.07\%$$

APPENDIX F TO DIRECT TESTIMONY OF PAUL R. MOUL

FLOTATION COST ADJUSTMENT

The rate of return on common equity must be high enough to avoid dilution when additional common equity is issued. In this regard, the rate of return on book common equity for public utilities requires recognition of specific factors other than just the market-determined cost of equity. A market price of common stock above book value is necessary to attract future capital on reasonable terms in competition with other seekers of equity capital. Non-regulated companies traditionally have experienced common stock prices consistently above book value. For a public utility to be competitive in the capital markets, similar recognition should be provided, given the understated value of net plant investment which is represented by historical costs much lower than current cost. Moreover, the market value of a public utility stock must be above book value to provide recognition of market pressure, issuance and selling expenses which reduce the net proceeds realized from the sale of new shares of common stock. A market price of stock above book value will maintain the financial integrity of shares previously issued and is necessary to avoid dilution when new shares are offered.

The rate of return on common equity should provide for the underwriting discount and company issuance expenses associated with the sale of new common stock. It is the net proceeds, after payment of these costs that are available to the company, because the issuance costs are paid from the initial offering price to the public. Market pressure occurs when the news of an impending issue of new common shares impacts the pre-offering price of stock. The stock price often declines because of the prospect of an increase in the supply of shares. The difficulty encountered in measuring market pressure relates to the time frame considered, general market conditions, and management action during the offering period. An indication of negative market pressure could be the product of the techniques employed to measure pressure and not the prospect of an additional supply of shares related to the new issue.

Even in the situation where a company will not issue common stock during the near term, the flotation cost adjustment factor should be applied to the common equity cost rate. A public utility must be in a competitive capital attraction posture at all times. To deny recognition of a market value of equity above book value would be discriminatory when other comparable companies receive an allowance in this regard. Moreover, to reduce the return rate on common equity by failing to recognize this factor would likewise result in a company being less competitive in the bond market, because a lower resulting overall rate of return would provide less competitive fixed-charge coverage. It cannot be said that a public utility's stock price already considers an allowance for flotation costs. This is because investors in either fixed-income bonds or common stocks seek their required rate of return by reference to alternative investment opportunities, and are not concerned with the issuance costs incurred by a firm borrowing long-term debt or issuing common equity.

Historical data concerning issuance and selling expenses (excluding market pressure) is shown on Schedule 8. To adjust for the cost of raising new common equity capital, the rate of return on common equity should recognize an appropriate multiple in order to allow for a market price of stock above book value. This would provide recognition for flotation costs, which are shown to be 3.3% for public offerings of common stocks by electric companies from 2001 to 2004. Because these costs are not recovered elsewhere, they must be recognized in the rate of return. Since I apply the flotation cost to the entire cost of equity, I have only used a modification factor of 1.02 which is applied to the unadjusted DCF-measure of the cost of equity to cover issuance expense. If the modification factor were applied to only a portion of the cost of equity, such as just the dividend yield, then a higher factor would be necessary.

INTEREST RATES

Interest rates can be viewed in their traditional nominal terms (i.e., the stated rate of interest) and in real terms (i.e., the stated rate of interest less the expected rate of inflation). Absent consideration of inflation, the real rate of interest is determined generally by supply factors which are influenced by investors willingness to forego current consumption (i.e., to save) and demand factors that are influenced by the opportunities to derive income from productive investments. Added to the real rate of interest is compensation required by investors for the inflationary impact of the declining purchasing power of their income received in the future. While interest rates are clearly influenced by the changing annual rate of inflation, it is important to note that the expected rate of inflation, that is reflected in current interest rates, may be quite different than the prevailing rate of inflation.

Rates of interest also vary by the type of interest bearing instrument. Investors require compensation for the risk associated with the term of the investment and the risk of default. The risk associated with the term of the investment is usually shown by the yield curve, i.e., the difference in rates across maturities. The typical structure is represented by a positive yield curve which provides progressively higher interest rates as the maturities are lengthened. Flat (i.e., relatively level rates across maturities) or inverted (i.e., higher short-term rates than long-term rates) yield curves occur less frequently.

The risk of default is typically associated with the creditworthiness of the borrower. Differences in interest rates can be traced to the credit quality ratings assigned by the bond rating agencies, such as Moody's Investors Service, Inc. and Standard & Poor's Corporation. Obligations of the United States Treasury are usually considered to be free of default risk, and hence reflect only the real rate of interest, compensation for expected inflation, and maturity risk. The Treasury has been issuing inflation-indexed notes which automatically provide compensation to investors for future inflation, thereby providing a lower current yield on these issues.

Interest Rate Environment

Federal Reserve Board ("Fed") policy actions which impact directly short-term interest rates also substantially affect investor sentiment in long-term fixed-income securities markets. In this regard, the Fed has often pursued policies designed to build investor confidence in the fixed-income securities market. Formative Fed policy has had a long history, as exemplified by the historic 1951 Treasury-Federal Reserve Accord, and more recently, deregulation within the financial system which increased the level and volatility of interest rates. The Fed has indicated that it will follow a monetary policy designed to promote noninflationary economic growth.

As background to the recent levels of interest rates, history shows that the Open Market Committee of the Federal Reserve board ("FOMC") began a series of moves toward lower short-term interest rates in mid-1990 -- at the outset of the previous recession. Monetary policy was influenced at that time by (i) steps taken to reduce the federal budget deficit, (ii) slowing economic growth, (iii) rising unemployment, and (iv) measures intended to avoid a credit crunch. Thereafter, the Federal government initiated several bold proposals to deal with future borrowings by the Treasury. With lower expected federal budget deficits and reduced Treasury borrowings, together with limitations on the supply of new 30-year Treasury bonds, long-term interest rates declined to a twenty-year low, reaching a trough of 5.78% in October 1993.

On February 4, 1994, the FOMC began a series of increases in the Fed Funds rate (i.e., the interest rate on excess overnight bank reserves). The initial increase represented the first rise in short-term interest rates in five years. The series of seven increases doubled the Fed Funds rate to 6%. The increases in short-term interest rates also caused long-term rates to move up, continuing a trend which began in the fourth quarter of 1993. The cyclical peak in long-term interest rates was reached on November 7 and 14, 1994 when 30-year Treasury bonds attained an 8.16% yield. Thereafter, long-term Treasury bond yields generally declined.

Beginning in mid-February 1996, long-term interest rates moved upward from their previous lows. After initially reaching a level of 6.75% on March 15, 1996, long-term interest rates continued to climb and reached a peak of 7.19% on July 5 and 8, 1996. For the period leading up to the 1996 Presidential election, long-term Treasury bonds generally traded within this range. After the election, interest rates moderated, returning to a level somewhat below the previous trading range. Thereafter, in December 1996, interest rates returned to a range of 6.5% to 7.0% which existed for much of 1996.

On March 25, 1997, the FOMC decided to tighten monetary conditions through a one-quarter percentage point increase in the Fed Funds rate. This tightening increased the Fed Funds rate to 5.5%. In making this move, the FOMC stated that it was concerned by persistent strength of demand in the economy, which it feared would increase the risk of inflationary imbalances that could eventually interfere with the long economic expansion.

In the fourth quarter of 1997, the yields on Treasury bonds began to decline rapidly in response to an increase in demand for Treasury securities caused by a flight to safety triggered by the currency and stock market crisis in Asia. Liquidity provided by the Treasury market makes these bonds an attractive investment in times of crisis. This is because Treasury securities encompass a very large market which provides ease of trading and carry a premium for safety. During the fourth quarter of 1997, Treasury bond yields pierced the psychologically important 6% level for the first time since 1993.

Through the first half of 1998, the yields on long-term Treasury bonds fluctuated within a range of about 5.6% to 6.1% reflecting their attractiveness and safety. In the third quarter of 1998, there was further deterioration of investor confidence in global financial markets. This loss of confidence followed the moratorium (i.e., default) by Russia on its sovereign debt and fears associated with problems in Latin America. While not significant to the global economy in the aggregate, the August 17 default by Russia had a significant negative impact on investor confidence, following earlier discontent surrounding the crisis in Asia. These events subsequently led to a general pull back of risk-taking as displayed by banks growing reluctance to lend, worries of an expanding credit crunch, lower stock prices, and higher yields on bonds of riskier companies. These events contributed to the failure of the hedge fund, Long-Term Capital Management.

In response to these events, the FOMC cut the Fed Funds rate just prior to the mid-term Congressional elections. The FOMC's action was based upon concerns over how increasing weakness in foreign economies would affect the U.S. economy. As recently as July 1998, the FOMC had been more concerned about fighting inflation than the state of the economy. The initial rate cut was the first of three reductions by the FOMC. Thereafter, the yield on long-term Treasury bonds reached a 30-year low of 4.70% on October 5, 1998. Long-term Treasury yields below 5% had not been seen since 1967. Unlike the first rate cut that was widely anticipated, the second rate reduction by the FOMC was a surprise to the markets. A third reduction in short-term interest rates occurred in November 1998 when the FOMC reduced the Fed Funds rate to 4.75%.

All of these events prompted an increase in the prices for Treasury bonds which lead to the low yields described above. Another factor that contributed to the decline in yields on long-term Treasury bonds was a reduction in the supply of new Treasury issues coming to market due to the Federal budget surplus -- the first in nearly 30 years. The dollar amount of Treasury bonds being issued declined by 30% in two years thus resulting in higher prices and lower yields. In addition, rumors of some struggling hedge funds unwinding their positions further added to the gains in Treasury bond prices.

The financial crisis that spread from Asia to Russia and to Latin America pushed nervous investors from stocks into Treasury bonds, thus increasing demand for bonds, just when supply was shrinking. There was also a move from corporate bonds to Treasury bonds to take advantage of appreciation in the Treasury market. This resulted in a certain amount of exuberance for Treasury bond investments that formerly was reserved for the stock market. Moreover, yields in the fourth quarter of 1998 became extremely volatile as shown by Treasury yields that fell from 5.10% on September 29 to 4.70 percent on October 5, and thereafter returned to 5.10% on October 13. A decline and rebound of 40 basis points in Treasury yields in a two-week time frame is remarkable.

Beginning in mid-1999, the FOMC raised interest rates on six occasions reversing its actions in the fall of 1998. On June 30, 1999, August 24, 1999, November 16, 1999, February 2, 2000, March 21, 2000, and May 16, 2000, the FOMC raised the Fed Funds rate to 6.50%. This brought the Fed Funds rate to its highest level since 1991, and was 175 basis points higher than the level that occurred at the height of the Asian currency and stock market crisis. At the time, these actions were taken in response to more normally functioning financial markets, tight labor markets, and a reversal of the monetary ease that was required earlier in response to the global financial market turmoil.

As the year 2000 drew to a close, economic activity slowed and consumer confidence began to weaken. In two steps at the beginning and at the end of January 2001, the FOMC reduced the Fed Funds rate by one percentage point. These actions brought the Fed Funds rate to 5.50%. The FOMC described its actions as "a rapid and forceful response of monetary policy" to eroding consumer and business confidence exemplified by weaker retail sales and business spending on capital equipment and cut backs in manufacturing production. Subsequently, on March 20, 2001, April 18, 2001, May 15, 2001, June 27, 2001, and August 21, 2001, the FOMC lowered the Fed Funds in steps consisting of three 50 basis points decrements followed by two 25 basis points decrements. These actions took the Fed Funds rate to 3.50%. The FOMC observed on August 21, 2001:

> "Household demand has been sustained, but business profits and capital spending continue to weaken and growth abroad is slowing, weighing on the U.S. economy. The associated easing of pressures on labor and product markets is expected to keep inflation contained.
>
> Although long-term prospects for productivity growth and the economy remain favorable, the Committee continues to believe that against the background of its long-run goals of price stability and sustainable economic growth and of the information currently available, the risks are weighted mainly toward conditions that may generate economic weakness in the foreseeable future."

After the terrorist attack on September 11, 2001, the FOMC made two additional 50 basis points reductions in the Fed Funds rate. The first reduction occurred on September 17, 2001 and followed the four-day closure of the financial markets following the terrorist attacks. The second reduction occurred at the October 2 meeting of the FOMC where it observed:

> "The terrorist attacks have significantly heightened uncertainty in an economy that was already weak. Business and household spending as a consequence are being further damped. Nonetheless, the long-term prospects for productivity growth and the economy remain favorable and should become evident once the unusual forces restraining demand abate."

Afterward, the FOMC reduced the Fed Funds rate by 50 basis points on November 6, 2001 and by 25 basis points on December 11, 2001. In total, short-term interest rates were reduced by the FOMC eleven (11) times during the year 2001. These actions cut the Fed Funds rate by 4.75% and resulted in 1.75% for the Fed Funds rate.

In an attempt to deal with weakening fundamentals in the economy recovering from the recession that began in March 2001, the FOMC provided a psychologically important one-half percentage point reduction in the federal funds rate. The rate cut was twice as large as the market expected, and brought the fed funds rate to 1.25% on November 6, 2002. The FOMC stated that:

> "The Committee continues to believe that an accommodative stance of monetary policy, coupled with still-robust underlying growth in productivity, is providing important ongoing support to economic activity. However, incoming economic data have tended to confirm that greater uncertainty, in part attributable to heightened geopolitical risks, is currently inhibiting spending, production, and employment. Inflation and inflation expectations remain well contained.
>
> In these circumstances, the Committee believes that today's additional monetary easing should prove helpful as the economy works its way through this current soft spot. With this action, the Committee believes that, against the background of its long-run goals of price stability and sustainable economic growth and of the information currently available, the risks are balanced with respect to the prospects for both goals in the foreseeable future."

As 2003 unfolded, there was a continuing expectation of lower yields on Treasury securities. In fact, the yield on ten-year Treasury notes reached a 45-year low near the end of the second quarter of 2003. For long-term Treasury bonds, those yields culminated with a 4.24% yield on June 13, 2003. Soon thereafter, the FOMC reduced the Fed Funds rate by 25 basis points on June 25, 2003. In announcing its action, the FOMC stated:

> "The Committee continues to believe that an accommodative stance of monetary policy, coupled with still robust underlying growth in productivity, is providing important ongoing support to economic activity. Recent signs point to a firming in spending, markedly improved financial conditions, and labor and product markets that are stabilizing. The economy, nonetheless, has yet to exhibit sustainable growth. With inflationary expectations subdued, the Committee judged that a slightly more expansive monetary policy would add further support for an economy which it expects to improve over time."

Thereafter, intermediate and long-term Treasury yields moved marketedly higher. Higher yields on long-term Treasury bonds, which exceeded 5.00% can be traced to: (i) the market's disappointment that the Fed Funds rate was not reduced below 1.00%, (ii) an indication that the Fed will not use unconventional methods for implementing monetary policy, (iii) growing confidence in a strengthening economy, and (iv) a Federal budget deficit that is projected to be $455 billion in 2003 (reported, subsequently, the actually deficit was $374 billion) and $475 billion in 2004 (revised subsequently, the estimated deficit is $500 billion in 2004). All these factors significantly changed the seniment in the bond market.

For the remainder of 2003, the FOMC continued with its balanced monetary policy, thereby retaining the 1% Fed Funds rate. However, in 2004, the FOMC initiated a policy of moving toward a more neutral Fed Funds rate (i.e., removing the bias of abnormal low rates). On June 30, 2004, August 10, 2004, September 21, 2004, November 10, 2004, December 14, 2004, February 2, 2005, March 22, 2005, May 3, 2005, and June 30, 2005, the FOMC increased the Fed Funds rate in nine 25 basis point increments. These policy actions are widely interpreted as the beginning of the process of moving toward a more neutral range for the Fed Funds rate. In its June 30, 2005 press relase, the FOMC stated:

> The Federal Open Market Committee decided today to raise its target for the federal funds rate by 25 basis points to 3-1/4 percent.
>
> The Committee believes that, even after this action, the stance of monetary policy remains accommodative and, coupled with robust underlying growth in productivity, is providing ongoing support to economic activity. Although energy prices have risen further, the expansion remains firm and labor market conditions continue to improve gradually. Pressures on inflation have stayed elevated, but longer-term inflation expectations remain well contained.
>
> The Committee perceives that, with appropriate monetary policy action, the upside and downside risks to the attainment of both sustainable growth and price stability should be kept roughly equal. With underlying inflation expected to be contained, the Committee believes that policy accommodation can be removed at a pace that is likely to be measured. Nonetheless, the Committee will respond to changes in economic prospects as needed to fulfill its obligation to maintain price stability.

Public Utility Bond Yields

The Risk Premium analysis of the cost of equity is represented by the combination of a firm's borrowing rate for long-term debt capital plus a premium that is required to reflect the additional risk associated with the equity of a firm as explained in Appendix H. Due to the senior nature of the long-term debt of a firm, its cost is lower than the cost of equity due to the prior claim which lenders have on the earnings and assets of a corporation.

As a generalization, all interest rates track to varying degrees of the benchmark yields established by the market for Treasury securities. Public utility bond yields usually reflect the underlying Treasury yield associated with a given maturity plus a spread to reflect the specific credit quality of the issuing public utility. Market sentiment can also have an influence on the spreads as described below. The spread in the yields on public utility bonds and Treasury bonds varies with market conditions, as does the relative level of interest rates at varying maturities shown by the yield curve.

Pages 1 and 2 of Schedule 10 provide the recent history of long-term public utility bond yields for the rating categories of Aa, A and Baa (no yields are shown for Aaa rated public utility bonds because this index has been discontinued). The top four rating categories of Aaa, Aa, A, and Baa are known as "investment grades" and are generally regarded as eligible for bank investments under commercial banking regulations. These investment grades are distinguished from "junk" bonds which have ratings of Ba and below.

A relatively long history of the spread between the yields on long-term A-rated public utility bonds and 20-year Treasury bonds is shown on page 3 of Schedule 10. There, it is shown that those spreads were about the one percentage during for the years 1994 through 1997. With the aversion to risk and flight to quality described earlier, a significant widening of the spread in the yields between corporate (e.g., public utility) and Treasury bonds developed in 1998, after an initial widening of the spread that began in the fourth quarter of 1997. The significant widening of spreads in 1998 was unexpected by some technically savvy investors, as shown by the debacle at the Long-Term Capital Management hedge fund. When Russia defaulted its debt on August 17, some investors had to cover short positions when Treasury prices spiked upward. Short covering by investors that guessed wrong on the relationship between corporate and Treasury bonds also contributed to run-up in Treasury bond prices by increasing the demand for them. This helped to contribute to a widening of the spreads between corporate and Treasury bonds.

As shown on page 3 of Schedule 10, the spread in yields between A-rated public utility bonds and 20-year Treasury bonds were about one percentage point prior to 1998, 1.32% in 1998, 1.42% in 1999, 2.01% in 2000, 2.13% in 2001, 1.94% in 2002, 1.62% in 2003, and 1.11% in 2004. As shown by the monthly data presented on pages 4 and 5 of Schedule 10, the interest rate spread between the yields on 20-year Treasury bonds and A-rated public utility bonds was 1.02 percentage points for the twelve-months ended June 2005. For the six- and three-month periods ending June 2005, the yield spread was 0.98% and 0.97%, respectively.

<u>Risk-Free Rate of Return in the CAPM</u>

Regarding the risk-free rate of return (see Appendix I), pages 2 and 3 of Schedule 12 provide the yields on the broad spectrum of Treasury Notes and Bonds. Some practitioners of the CAPM would advocate the use of short-term treasury yields (and some would argue for the yields on 91-day Treasury Bills). Other advocates of the CAPM would advocate the use of longer-term treasury yields as the best measure of a risk-free rate of return. As Ibbotson has indicated:

> The Cost of Capital in a Regulatory Environment. When discounting cash flows projected over a long period, it is necessary to discount them by a long-term cost of capital. Additionally, regulatory processes for setting rates often specify or suggest that the desired rate of return for a regulated firm is that which would allow the firm to attract and retain debt and equity capital over the long term. Thus, the long-term cost of capital is typically the appropriate cost of capital to use in regulated ratesetting. (Stocks, Bonds, Bills and Inflation - 1992 Yearbook, pages 118-119)

As indicated above, long-term Treasury bond yields represent the correct measure of the risk-free rate of return in the traditional CAPM. Very short term yields on Treasury bills should be avoided for several reasons. First, rates should be set on the basis of financial conditions that will exist during the effective period of the proposed rates. Second, 91-day Treasury bill yields are more volatile than longer-term yields and are greatly influenced by FOMC monetary policy, political, and economic situations. Moreover, Treasury bill yields have been shown to be empirically inadequate for the CAPM. Some advocates of the theory would argue that the risk-free rate of return in the CAPM should be derived from quality long-term corporate bonds.

RISK PREMIUM ANALYSIS

The cost of equity requires recognition of the risk premium required by common equities over long-term corporate bond yields. In the case of senior capital, a company contracts for the use of long-term debt capital at a stated coupon rate for a specific period of time and in the case of preferred stock capital at a stated dividend rate, usually with provision for redemption through sinking fund requirements. In the case of senior capital, the cost rate is known with a high degree of certainty because the payment for use of this capital is a contractual obligation, and the future schedule of payments is known. In essence, the investor-expected cost of senior capital is equal to the realized return over the entire term of the issue, absent default.

The cost of equity, on the other hand, is not fixed, but rather varies with investor perception of the risk associated with the common stock. Because no precise measurement exists as to the cost of equity, informed judgment must be exercised through a study of various market factors which motivate investors to purchase common stock. In the case of common equity, the realized return rate may vary significantly from the expected cost rate due to the uncertainty associated with earnings on common equity. This uncertainty highlights the added risk of a common equity investment.

As one would expect from traditional risk and return relationships, the cost of equity is affected by expected interest rates. As noted in Appendix G, yields on long-term corporate bonds traditionally consist of a real rate of return without regard to inflation, an increment to reflect investor perception of expected future inflation, the investment horizon shown by the term of the issue until maturity, and the credit risk associated with each rating category.

The Risk Premium approach recognizes the required compensation for the more risky common equity over the less risky secured debt position of a lender. The cost of equity stated in terms of the familiar risk premium approach is:

$$k=i+RP$$

where, the cost of equity *("k")* is equal to the interest rate on long-term corporate debt *("i")*, plus an equity risk premium *("RP")* which represents the additional compensation for the riskier common equity.

Equity Risk Premium

The equity risk premium is determined as the difference in the rate of return on debt capital and the rate of return on common equity. Because the common equity holder has only a residual claim on earnings and assets, there is no assurance that achieved returns on common equities will equal expected returns. This is quite different from returns on bonds, where the investor realizes the expected return during the entire holding period, absent default. It is for this reason that common equities are always more risky than senior debt securities. There are investment strategies available to bond portfolio managers that immunize bond returns against fluctuations in interest rates because bonds are redeemed through sinking funds or at maturity, whereas no such redemption is mandated for public utility common equities.

It is well recognized that the expected return on more risky investments will exceed the required yield on less risky investments. Neither the possibility of default on a bond nor the maturity risk detracts from the risk analysis, because the common equity risk rate differential (i.e., the investor-required risk premium) is always greater than the return components on a bond. It should also be noted that the investment horizon is typically long-run for both corporate debt and equity, and that the risk of default (i.e., corporate bankruptcy) is a concern to both debt and equity investors. Thus, the required yield on a bond provides a benchmark or starting point with which to track and measure the cost rate of common equity capital. There is no need to segment the bond yield according to its components, because it is the total return demanded by investors that is important for determining the risk rate differential for common equity. This is because the complete bond yield provides the basis to determine the differential, and as such, consistency requires that the computed differential must be applied to the complete bond yield when applying the risk premium approach. To apply the risk rate differential to a partial bond yield would result in a misspecification of the cost of equity because the computed differential was initially determined by reference to the entire bond return.

The risk rate differential between the cost of equity and the yield on long-term corporate bonds can be determined by reference to a comparison of holding period returns (here defined as one year) computed over long time spans. This analysis assumes that over long periods of time investors' expectations are on average consistent with rates of return actually achieved. Accordingly, historical holding period returns must not be analyzed over an unduly short period because near-term realized results may not have fulfilled investors' expectations. Moreover, specific past period results may not be representative of investment fundamentals expected for the future. This is especially apparent when the holding period returns include negative returns which are not representative of either investor requirements of the past or investor expectations for the future. The short-run phenomenon of unexpected returns (either positive or negative) demonstrates that an unduly short historical period would not adequately support a risk premium analysis. It is important to distinguish between investors' motivation to invest, which encompass positive return expectations, and the knowledge that losses can occur. No rational investor would forego payment for the use of capital, or expect loss of principal, as a basis for investing. Investors will hold cash rather than invest with the expectation of a loss.

Within these constraints, page 1 of Schedule 11 provides the historical holding period returns for the S&P Public Utility Index which has been independently computed and the historical holding period returns for the S&P Composite Index which have been reported in Stocks, Bonds, Bills and Inflation published by Ibbotson & Associates. The tabulation begins with 1928 because January 1928 is the earliest monthly dividend yield for the S&P Public Utility Index. I have considered all reliable data for this study to avoid the introduction of a particular bias to the results. The measurement of the common equity return rate differential is based upon actual capital market performance using realized results. As a consequence, the underlying data for this risk premium approach can be analyzed with a high degree of precision. Informed professional judgment is required only to interpret the results of this study, but not to quantify the component variables.

The risk rate differentials for all equities, as measured by the S&P Composite, are established by reference to long-term corporate bonds. For public utilities, the risk rate differentials are computed with the S&P Public Utilities as compared with public utility bonds.

The measurement procedure used to identify the risk rate differentials consisted of arithmetic means, geometric means, and medians for each series. Measures of the central tendency of the results from the historical periods provide the best indication of representative rates of return. In regulated ratesetting, the correct measure of the equity risk premium is the arithmetic mean because a utility must expect to earn its cost of capital in each year in order to provide investors with their long-term expectations. In other contexts, such as pension determinations, compound rates of return, as shown by the geometric means, may be appropriate. The median returns are also appropriate in ratesetting because they are a measure of the central tendency of a single period rate of return. Median values have also been considered in this analysis because they provide a return which divides the entire series of annual returns in half and are representative of a return that symbolizes, in a meaningful way, the central tendency of all annual returns contained within the analysis period. Medians are regularly included in many investor-influencing publications.

As previously noted, the arithmetic mean provides the appropriate point estimate of the risk premium. As further explained in Appendix I, the long-term cost of capital in rate cases requires the use of the arithmetic means. To supplement my analysis, I have also used the rates of return taken from the geometric mean and median for each series to provide the bounds of the range to measure the risk rate differentials. This further analysis shows that when selecting the midpoint from a range established with the geometric means and medians, the arithmetic mean is indeed a reasonable measure for the long-term cost of capital. For the years 1928 through 2004, the risk premiums for each class of equity are:

	S&P Composite	S&P Public Utilities
Arithmetic Mean	5.86%	5.15%
Geometric Mean	4.21%	3.05%
Median	10.17%	6.61%
Midpoint of Range	7.19%	4.83%
Average	6.53%	4.99%

The empirical evidence suggests that the common equity risk premium is higher for the S&P Composite Index compared to the S&P Public Utilities.

If, however, specific historical periods were also analyzed in order to match more closely historical fundamentals with current expectations, the results provided on page 2 of Schedule 11 should also be considered. One of these sub-periods included the 53-year period, 1952-2004. These years follow the historic 1951 Treasury-Federal Reserve Accord which affected monetary policy and the market for government securities.

A further investigation was undertaken to determine whether realignment has taken place subsequent to the historic 1973 Arab Oil embargo and during the deregulation of the financial markets. In each case, the public utility risk premiums were computed by using the arithmetic mean, and the geometric means and medians to establish the range shown by those values. The time periods covering the more recent periods 1974 through 2004 and 1979 through 2004 contain events subsequent to the initial oil shock and the advent of monetarism as Fed policy, respectively. For the 53-year, 31-year and 26-year periods, the public utility risk premiums were 5.75%, 4.85%, and 4.91% respectively, as shown by the average of the specific point-estimates and the midpoint of the ranges provided on page 2 of Schedule 11.

CAPITAL ASSET PRICING MODEL

Modern portfolio theory provides a theoretical explanation of expected returns on portfolios of securities. The Capital Asset Pricing Model ("CAPM") attempts to describe the way prices of individual securities are determined in efficient markets where information is freely available and is reflected instantaneously in security prices. The CAPM states that the expected rate of return on a security is determined by a risk-free rate of return plus a risk premium which is proportional to the non-diversifiable (or systematic) risk of a security.

The CAPM theory has several unique assumptions that are not common to most other methods used to measure the cost of equity. As with other market-based approaches, the CAPM is an expectational concept. There has been significant academic research conducted that found that the empirical market line, based upon historical data, has a less steep slope and higher intercept than the theoretical market line of the CAPM. For equities with a beta less than 1.0, such as utility common stocks, the CAPM theoretical market line will underestimate the realistic expectation of investors in comparison with the empirical market line which shows that the CAPM may potentially misspecify investors' required return.

The CAPM considers changing market fundamentals in a portfolio context. The balance of the investment risk, or that characterized as unsystematic, must be diversified. Some argue that diversifiable (unsystematic) risk is unimportant to investors. But this contention is not completely justified because the business and financial risk of an individual company, including regulatory risk, are widely discussed within the investment community and therefore influence investors in regulated firms. In addition, I note that the CAPM assumes that through portfolio diversification, investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Because it is not known whether the average investor holds a well-diversified portfolio, the CAPM must also be used with other models of the cost of equity.

To apply the traditional CAPM theory, three inputs are required: the beta coefficient *("β")*, a risk-free rate of return *("Rf")*, and a market premium *("Rm - Rf")*. The cost of equity stated in terms of the CAPM is:

$$k = Rf + \beta\,(Rm - Rf)$$

As previously indicated, it is important to recognize that the academic research has shown that the security market line was flatter than that predicted by the CAPM theory and it had a higher intercept than the risk-free rate. These tests indicated that for portfolios with betas less than 1.0, the traditional CAPM would understate the return for such stocks. Likewise, for portfolios with betas above 1.0, these companies had lower returns than indicated by the traditional CAPM theory. Once again, CAPM assumes that through portfolio diversification investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Therefore, the CAPM must also be used with other models of the cost of equity, especially when it is not known whether the average public utility investor holds a well-diversified portfolio.

Beta

The beta coefficient is a statistical measure which attempts to identify the non-diversifiable (systematic) risk of an individual security and measures the sensitivity of rates of return on a particular security with general market movements. Under the CAPM theory, a security that has a beta of 1.0 should theoretically provide a rate of return equal to the return rate provided by the market. When employing stock price changes in the derivation of beta, a stock with a beta of 1.0 should exhibit a movement in price which would track the movements in the overall market prices of stocks. Hence, if a particular investment has a beta of 1.0, a one percent increase in the return on the market will result, on average, in a one percent increase in the return on the particular investment. An investment which has a beta less than 1.0 is considered to be less risky than the market.

The beta coefficient ("β"), the one input in the CAPM application which specifically applies to an individual firm, is derived from a statistical application which regresses the returns on an individual security (dependent variable) with the returns on the market as a whole (independent variable). The beta coefficients for utility companies typically describe a small proportion of the total investment risk because the coefficients of determination (R^2) are low.

Page 1 of Schedule 12 provides the betas published by Value Line. By way of explanation, the Value Line beta coefficient is derived from a "straight regression" based upon the percentage change in the weekly price of common stock and the percentage change weekly of the New York Stock Exchange Composite average using a five-year period. The raw historical beta is adjusted by Value Line for the measurement effect resulting in overestimates in high beta stocks and underestimates in low beta stocks. Value Line then rounds its betas to the nearest .05 increment. Value Line does not consider dividends in the computation of its betas.

Market Premium

The final element necessary to apply the CAPM is the market premium. The market premium by definition is the rate of return on the total market less the risk-free rate of return

("Rm - Rf"). In this regard, the market premium in the CAPM has been calculated from the total return on the market of equities using forecast and historical data. The future market return is established with forecasts by Value Line using estimated dividend yields and capital appreciation potential.

With regard to the forecast data, I have relied upon the Value Line forecasts of capital appreciation and the dividend yield on the 1,700 stocks in the Value Line Survey. According to the July 1, 2005, edition of The Value Line Investment Survey Summary and Index, (see page 5 of Schedule 12) the total return on the universe of Value Line equities is:

	Dividend Yield	+	Median Appreciation Potential	=	Median Total Return
As of July 1, 2005	1.6%	+	10.67%[6]	=	12.27%

The tabulation shown above provides the dividend yield and capital gains yield of the companies followed by Value Line. Another measure of the total market return is provided by the DCF return on the S&P 500 Composite index. As shown below, that return is 12.51%.

DCF Result for the S&P 500 Composite							
D/P	(	1+.5g	)	+	g	=	k
1.80%	(	1.05305	)	+	10.61%	=	12.51%
where:		Price (P)		at	30-Jun-2005	=	1191.33
		Dividend (D)		for	2nd Qtr '05	=	5.36
		Dividend (D)			annualized	=	21.44
		Growth (g)			First Call EpS	=	10.61%

Using these indicators, the total market return is 12.39% (12.27% + 12.51% = 24.78% ÷ 2) using both the Value Line and S&P derived returns. With the 12.39% forecast market return

[6] The estimated median appreciation potential is forecast to be 50% for 3 to 5 years hence. The annual capital gains yield at the midpoint of the forecast period is 10.67% (i.e., $1.50^{.25} - 1$).

and the 5.50% risk-free rate of return, a 6.89% (12.39% - 5.50%) market premium would be indicated using forecast market data.

With regard to the historical data, I provided the rates of return from long-term historical time periods that have been widely circulated among the investment and academic community over the past several years, as shown on page 6 of Schedule 12. These data are published by Ibbotson Associates in its Stocks, Bonds, Bills and Inflation ("SBBI"). From the data provided on page 6 of Schedule 12, I calculate a market premium using the common stock arithmetic mean returns of 12.4% less government bond arithmetic mean returns of 5.8%. For the period 1926-2004, the market premium was 6.6% (12.4% - 5.8%). I should note that the arithmetic mean must be used in the CAPM because it is a single period model. It is further confirmed by Ibbotson who has indicated:

> *Arithmetic Versus Geometric Differences*
> For use as the expected equity risk premium in the CAPM, the *arithmetic* or *simple difference* of the *arithmetic* means of stock market returns and riskless rates is the relevant number. This is because the CAPM is an additive model where the cost of capital is the sum of its parts. Therefore, the CAPM expected equity risk premium must be derived by arithmetic, *not geometric*, subtraction.
>
> *Arithmetic Versus Geometric Means*
> The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values. This makes the arithmetic mean return appropriate for computing the cost of capital. The discount rate that equates expected (mean) future values with the present value of an investment is that investment's cost of capital. The logic of using the discount rate as the cost of capital is reinforced by noting that investors will discount their (mean) ending wealth values from an investment back to the present using the arithmetic mean, for the reason given above. They will

> therefore require such an expected (mean) return prospectively (that is, in the present looking toward the future) to commit their capital to the investment. (Stocks, Bonds, Bills and Inflation - 1996 Yearbook, pages 153-154)

For the CAPM, a market premium of 6.75% (6.6% + 6.89% = 13.49% ÷ 2) would be reasonable which is the average of the 6.6% using historical data and a market premium of 6.89% using forecasts.

COMPARABLE EARNINGS APPROACH

Value Line's analysis of the companies that it follows includes a wide range of financial and market variables, including nine items that provide ratings for each company. From these nine items, one category has been removed dealing with industry performance because, under approach employed, the particular business type is not significant. In addition, two categories have been ignored that deal with estimates of current earnings and dividends because they are not useful for comparative purposes. The remaining six categories provide relevant measures to establish comparability. The definitions for each of the six criteria (from the Value Line Investment Survey - Subscriber Guide) follow:

Timeliness Rank

The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

Safety Rank

A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others. The ratings range from A++ to C in nine steps. (For screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating an ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies.

Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.

Exhibit No. PRM-1

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY CASE NO. 2005-000341

FINANCIAL EXHIBIT TO ACCOMPANY

THE DIRECT TESTIMONY OF

PAUL R. MOUL

September 26, 2005

Kentucky Power Company
Index of Schedules

Kentucky Power Company
Summary Cost of Capital
at June 30, 2005

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	56.55%	5.70%	3.22%
Short-Term Debt	0.39%	3.34%	0.01%
Accts Rec Financing	3.52%	2.99%	0.11%
Total Debt	60.46%		3.34%
Common Equity	39.54%	11.50%	4.55%
Total	100.00%		7.89%

Indicated levels of fixed charge coverage assuming that the Company could actually achieve its overall cost of capital:

Pre-tax coverage of interest expense based upon a 40.3625% composite federal and state income tax rate (10.97% ÷ 3.34%)	3.28 x
Post-tax coverage of interest expense (7.89% ÷ 3.22%)	2.45 x

American Electric Power Company
Capitalization and Financial Statistics
2000-2004, Inclusive

	2004	2003	2002	2001	2000	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 21,172.0	$ 22,294.0	$ 19,013.0	$ 21,960.0	$ 19,917.0	
Short-Term Debt	$ 23.0	$ 326.0	$ 3,164.0	$ 3,155.0	$ 4,333.0	
Total Capital	$ 21,195.0	$ 22,620.0	$ 22,177.0	$ 25,115.0	$ 24,250.0	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	11 x	19 x	NMF x	15 x	40 x	21 x
Market/Book Ratio	154.5%	123.9%	137.7%	178.9%	147.4%	148.5%
Dividend Yield	4.4%	6.5%	7.5%	5.3%	6.4%	6.0%
Dividend Payout Ratio	49.2%	118.4%	3776.2%	77.1%	266.6%	857.5%
Capital Structure Ratios						
Based on Permanent Captial:						Average
Long-Term Debt	59.5%	64.4%	58.1%	58.4%	58.8%	59.8%
Preferred Stock	0.3%	0.3%	4.8%	4.1%	0.8%	2.1%
Common Equity	40.2%	35.3%	37.2%	37.5%	40.4%	38.1%
	100.0%	100.0%	100.1%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	59.5%	64.9%	64.1%	63.6%	66.1%	63.6%
Preferred Stock	0.3%	0.3%	4.1%	3.6%	0.7%	1.8%
Common Equity	40.2%	34.8%	31.9%	32.8%	33.2%	34.6%
	100.0%	100.0%	100.1%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity	13.8%	7.0%	0.3%	12.3%	4.6%	7.6%
Operating Ratio (1)	85.8%	84.3%	91.3%	96.1%	85.2%	88.5%
Coverage incl. AFUDC (2)						
Pre-tax: All Interest Charges	3.18 x	2.09 x	1.31 x	2.63 x	1.95 x	2.23 x
Post-tax: All Interest Charges	2.45 x	1.65 x	1.04 x	2.04 x	1.38 x	1.71 x
Overall Coverage: All Int. & Pfd. Div.	2.43 x	1.63 x	1.03 x	2.02 x	1.26 x	1.67 x
Coverage excl. AFUDC (3)						
Pre-tax: All Interest Charges	3.14 x	2.09 x	1.31 x	2.63 x	1.95 x	2.22 x
Post-tax: All Interest Charges	2.40 x	1.65 x	1.04 x	2.04 x	1.38 x	1.70 x
Overall Coverage: All Int. & Pfd. Div.	2.39 x	1.63 x	1.03 x	2.02 x	1.26 x	1.67 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	3.3%	0.0%	0.0%	0.0%	0.0%	0.7%
Effective Income Tax Rate	33.5%	40.3%	87.0%	36.0%	59.6%	51.3%
Internal Cash Generation/Construction (4)	105.6%	149.7%	117.5%	78.6%	45.8%	99.4%
Gross Cash Flow/ Avg. Total Debt(5)	17.2%	18.3%	18.7%	13.8%	13.0%	16.2%
Gross Cash Flow Interest Coverage(6)	3.97 x	4.17 x	4.60 x	3.28 x	2.33 x	3.67 x
Common Dividend Coverage (7)	4.22 x	4.29 x	3.55 x	2.86 x	2.01 x	3.39 x

See Page 2 for Notes.

American Electric Power Company
Capitalization and Financial Statistics
2000-2004, Inclusive

Notes:

(1) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.

(2) Coverage calculations represent the number of times available earnings including AFUDC (allowance for funds used during construction), as reported in its entirety, cover fixed charges.

(3) Coverage calculations represent the number of times available earnings excluding AFUDC (allowance for funds used during construction), as reported in its entirety, cover fixed charges.

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally generated funds from operations after payment of all cash dividends.

(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less AFUDC) as a percentage of average total debt.

(6) Gross Cash Flow plus interest charges divided by interest charges.

(7) Common dividend coverage is the relationship of internally generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Utility COMPUSTAT

Electric Group
Capitalization and Financial Statistics (1)
2000-2004, Inclusive

	2004	2003	2002	2001	2000	Average
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 9,793.0	$ 9,701.2	$ 9,265.5	$ 9,280.9	$ 7,017.8	
Short-Term Debt	$ 322.1	$ 309.3	$ 551.2	$ 410.6	$ 637.3	
Total Capital	$ 10,115.1	$ 10,010.5	$ 9,816.7	$ 9,691.5	$ 7,655.1	
Market-Based Financial Ratios						
Price-Earnings Multiple	17 x	17 x	13 x	14 x	14 x	15 x
Market/Book Ratio	178.8%	170.5%	162.7%	167.3%	170.4%	169.9%
Dividend Yield	4.2%	4.5%	4.9%	4.9%	5.7%	4.8%
Dividend Payout Ratio	72.3%	74.4%	64.5%	71.2%	71.6%	70.8%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	50.8%	54.5%	57.0%	56.7%	53.0%	54.4%
Preferred Stock	1.0%	1.1%	1.1%	1.5%	2.1%	1.4%
Common Equity	48.2%	44.5%	41.9%	41.8%	44.9%	44.2%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	54.2%	56.8%	60.2%	59.4%	58.9%	57.9%
Preferred Stock	1.0%	1.0%	1.1%	1.4%	2.0%	1.3%
Common Equity	44.8%	42.2%	38.8%	39.2%	39.2%	40.9%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity	11.3%	10.5%	12.9%	12.0%	12.5%	11.8%
Operating Ratio (2)	84.9%	86.0%	84.3%	85.8%	84.4%	85.1%
Coverage incl. AFUDC (3)						
Pre-tax: All Interest Charges	3.53 x	3.06 x	3.14 x	2.98 x	3.07 x	3.15 x
Post-tax: All Interest Charges	2.74 x	2.42 x	2.46 x	2.35 x	2.41 x	2.47 x
Overall Coverage: All Int. & Pfd. Div.	2.69 x	2.37 x	2.40 x	2.26 x	2.33 x	2.41 x
Coverage excl. AFUDC (4)						
Pre-tax: All Interest Charges	3.50 x	3.03 x	3.11 x	2.94 x	3.02 x	3.12 x
Post-tax: All Interest Charges	2.71 x	2.39 x	2.43 x	2.30 x	2.36 x	2.44 x
Overall Coverage: All Int. & Pfd. Div.	2.66 x	2.34 x	2.38 x	2.22 x	2.28 x	2.38 x
Quality of Earnings & Cash Flow						
AFUDC/Income Avail. for Common Equity	3.5%	3.1%	2.4%	3.5%	4.2%	3.3%
Effective Income Tax Rate	31.5%	25.2%	28.8%	21.7%	29.5%	27.3%
Internal Cash Generation/Construction (5	107.2%	102.0%	93.0%	84.9%	104.0%	98.2%
Gross Cash Flow/ Avg. Total Debt(6)	22.2%	20.4%	20.4%	20.5%	22.7%	21.2%
Gross Cash Flow Interest Coverage(7)	5.18 x	4.63 x	4.30 x	4.13 x	4.27 x	4.50 x
Common Dividend Coverage (8)	4.00 x	4.15 x	4.19 x	4.05 x	4.26 x	4.13 x

See Page 2 for Notes.

Electric Group
Capitalization and Financial Statistics
2000-2004, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.

(2) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.

(3) Coverage calculations represent the number of times available earnings including AFUDC (allowance for funds used during construction), as reported in its entirety, cover fixed charges.

(4) Coverage calculations represent the number of times available earnings excluding AFC (allowance for funds used during construction), as reported in its entirety, cover fixed charges.

(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends.

(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income tax and investment tax credits, less total AFUDC) as a percentage of average total debt.

(7) Gross Cash Flow plus interest charges divided by interest charges.

(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Basis of Selection

The group consists of the parent companies of the electric utilities that operate in the Great region of the U.S. To be included in the group, each holding company had to have publicly-traded common stock, a listing in The Value Line Investment Survey in the category "Electric Utility Industry," have not recently reduced or eliminated their common dividend, and not currently the target of a merger or acquisition.

		Corporate Credit Ratings		Stock	S&P Stock	Value Line
Ticker	Company	Moody's	S&P	Traded	Ranking	Beta
AEE	Ameren Corp.	A2	A-	NYSE	A-	0.75
DTE	DTE Energy Co.	Baa1	BBB+	NYSE	B+	0.70
EXC	Exelon Corp.	Baa1	A-	NYSE	B	0.75
FE	FirstEnergy Corp.	Baa2	BBB-	NYSE	B+	0.75
MGEE	MGE Energy, Inc.	Aa3	AA	NDQ	B+	0.60
VVC	Vectren Corp.	Baa1	A-	NYSE	B+	0.75
WPS	WPS Resources	Aa3	AA-	NYSE	B+	0.75
WEC	Wisconsin Energy	A1	A-	NYSE	B	0.70
	Average	A3	A-		B+	0.72

Note: Ratings are those of utility subsidiaries

Source of Information: Utility COMPUSTAT

Standard & Poor's Public Utilities
Capitalization and Financial Statistics (1)
2000-2004, Inclusive

	2004	2003	2002	2001	2000	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 14,204.1	$ 14,494.4	$14,111.6	$ 13,848.1	$11,801.3	
Short-Term Debt	$ 274.2	$ 259.4	$ 936.6	$ 1,195.1	$ 1,649.0	
Total Capital	$ 14,478.3	$ 14,753.8	$15,048.2	$ 15,043.2	$13,450.3	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	17 x	13 x	15 x	17 x	18 x	16 x
Market/Book Ratio	181.7%	147.9%	153.9%	194.3%	188.8%	173.3%
Dividend Yield	3.7%	4.0%	4.8%	3.9%	4.7%	4.2%
Dividend Payout Ratio	69.5%	59.6%	72.8%	61.6%	82.6%	69.2%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	59.2%	61.1%	61.7%	58.8%	57.5%	59.7%
Preferred Stock	1.9%	1.9%	2.5%	3.0%	2.7%	2.4%
Common Equity	38.9%	36.9%	35.8%	38.2%	39.8%	37.9%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	60.6%	62.5%	64.6%	62.8%	63.0%	62.7%
Preferred Stock	1.9%	1.9%	2.4%	2.7%	2.4%	2.3%
Common Equity	37.5%	35.6%	33.1%	34.5%	34.6%	35.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity	10.5%	9.7%	6.9%	14.2%	8.3%	9.9%
Operating Ratio (2)	82.2%	84.6%	85.1%	85.5%	86.8%	84.8%
Coverage incl. AFUDC (3)						
Pre-tax: All Interest Charges	2.86 x	2.49 x	2.28 x	2.81 x	2.55 x	2.60 x
Post-tax: All Interest Charges	2.30 x	2.05 x	1.89 x	2.19 x	2.01 x	2.09 x
Overall Coverage: All Int. & Pfd. Div.	2.27 x	2.02 x	1.85 x	2.14 x	1.95 x	2.05 x
Coverage excl. AFUDC (3)						
Pre-tax: All Interest Charges	2.83 x	2.45 x	2.23 x	2.78 x	2.52 x	2.56 x
Post-tax: All Interest Charges	2.27 x	2.01 x	1.85 x	2.15 x	1.98 x	2.05 x
Overall Coverage: All Int. & Pfd. Div.	2.24 x	1.98 x	1.81 x	2.10 x	1.92 x	2.01 x
Quality of Earnings & Cash Flow						
AFUDC/Income Avail. for Common Equity	2.2%	1.5%	2.6%	2.0%	5.3%	2.7%
Effective Income Tax Rate	26.4%	41.5%	29.3%	30.6%	35.6%	32.7%
Internal Cash Generation/Construction (4)	130.7%	128.7%	93.0%	95.9%	87.0%	107.1%
Gross Cash Flow/ Avg. Total Debt(5)	19.2%	19.3%	17.4%	17.7%	17.7%	18.3%
Gross Cash Flow Interest Coverage(6)	4.16 x	4.19 x	3.86 x	3.58 x	3.58 x	3.87 x
Common Dividend Coverage (7)	5.95 x	5.65 x	4.34 x	4.56 x	4.28 x	4.96 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2000-2004, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(3) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) as a percentage of average total debt.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(7) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

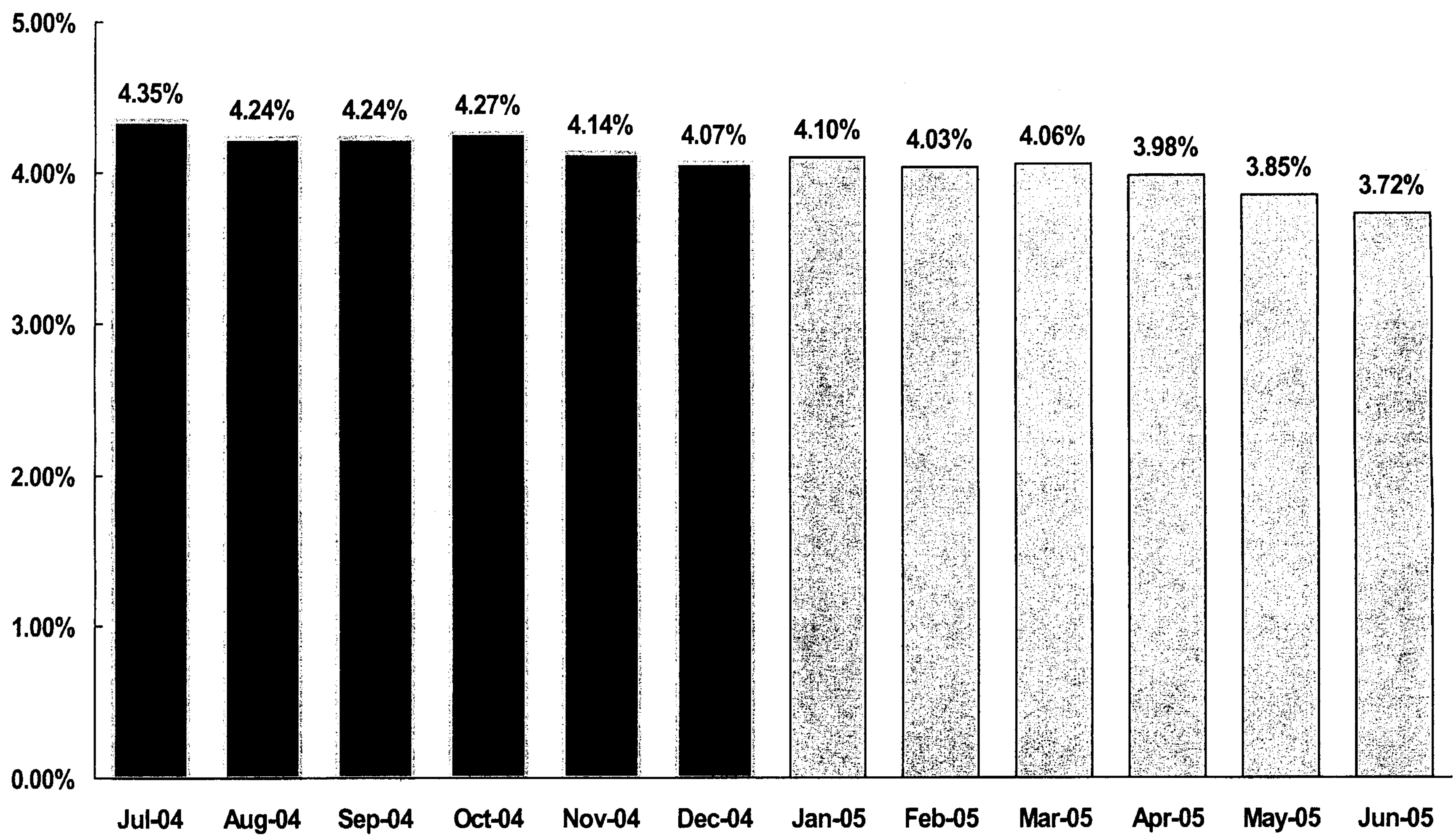
Standard & Poor's Public Utilities
Company Identities (1)

	Ticker	Credit Rating (2) Moody's	S&P	Common Stock Traded	S&P Stock Ranking	Value Line Beta
Allegheny Energy	AYE	Ba1	BB-	NYSE	A-	1.60
Ameren Corporation	AEE	A2	A-	NYSE	A-	0.75
American Electric Power	AEP	Baa2	BBB+	NYSE	B+	1.15
CenterPoint Energy	CNP	Baa3	BBB	NYSE	B	0.55
CINergy Corp.	CIN	Baa1	BBB+	NYSE	B	0.80
CMS Energy	CMS	Ba1	BB	NYSE	B	1.30
Consolidated Edison	ED	A1	A+	NYSE	A-	0.60
Constellation Energy Group	CEG	A2	A-	NYSE	A-	0.85
DTE Energy Co.	DTE	Baa1	BBB+	NYSE	B+	0.70
Dominion Resources	D	A3	A-	NYSE	B	0.85
Duke Energy	DUK	A3	A-	NYSE	A-	1.10
Edison Int'l	EIX	Ba3	BB	NYSE	B	1.05
El Paso Corp.	EP	B1	BB	NYSE	B+	1.85
Entergy Corp.	ETR	Baa3	BBB	NYSE	B	0.75
Exelon Corp.	EXC	A3	A-	NYSE	B	0.70
FPL Group	FPL	A1	A	NYSE	B+	0.70
FirstEnergy Corp.	FE	Baa2	BBB	NYSE	B+	0.75
Keyspan Energy	KSE	A3	A	NYSE	B+	0.80
Kinder Morgan	KMI	Baa2	BBB	NYSE	B	0.80
NICOR Inc.	GAS	Aa2	AA	NYSE	B+	1.05
NiSource Inc.	NI	Baa2	BBB	NYSE	A	0.75
PG&E Corp.	PCG	Caa2	D	NYSE	B	1.00
PPL Corp.	PPL	Baa1	A-	NYSE	B+	0.95
Peoples Energy	PGL	Aa3	A-	NYSE	B+	0.80
Pinnacle West Capital	PNW	Baa1	BBB	NYSE	A-	0.85
Progress Energy, Inc.	PGN	Baa1	BBB+	NYSE	A-	0.80
Public Serv. Enterprise Inc.	PEG	Baa1	BBB	NYSE	B+	0.85
Sempra Energy	SRE	A2	A+	NYSE	NR	0.90
Southern Co.	SO	A2	A	NYSE	A-	0.65
TECO Energy	TE	A2	BBB	NYSE	A	0.90
TXU CORP	TXU	Baa3	BBB	NYSE	B	1.00
Williams Cos.	WMB	Caa1	B+	NYSE	B	2.40
Xcel Energy Inc	XEL	Baa1	BBB+	NYSE	B+	0.80
Average for S&P Utilities		Baa2	BBB		B+	0.95

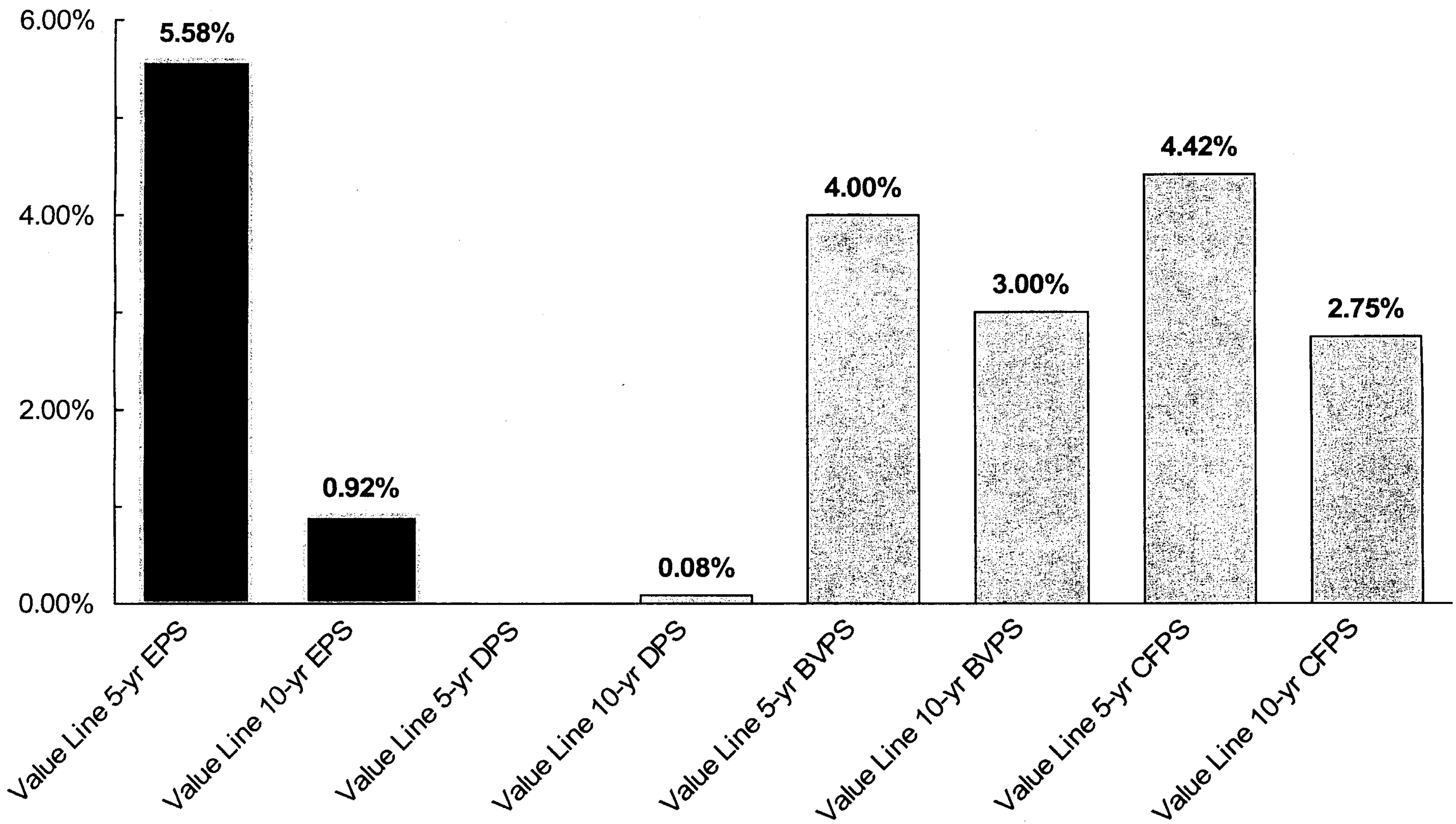
Note: * (1) Includes companies contained in S&P Utility Compustat. AES Corp., Calpine Corp., and Dynegy, Inc. are not included.
(2) Ratings are those of utility subsidiaries

Source of Information: Moody's Investors Service
Standard & Poor's Corporation
Standard & Poor's Stock Guide
Value Line Investment Survey for Windows

Electric Group
Monthly Dividend Yields



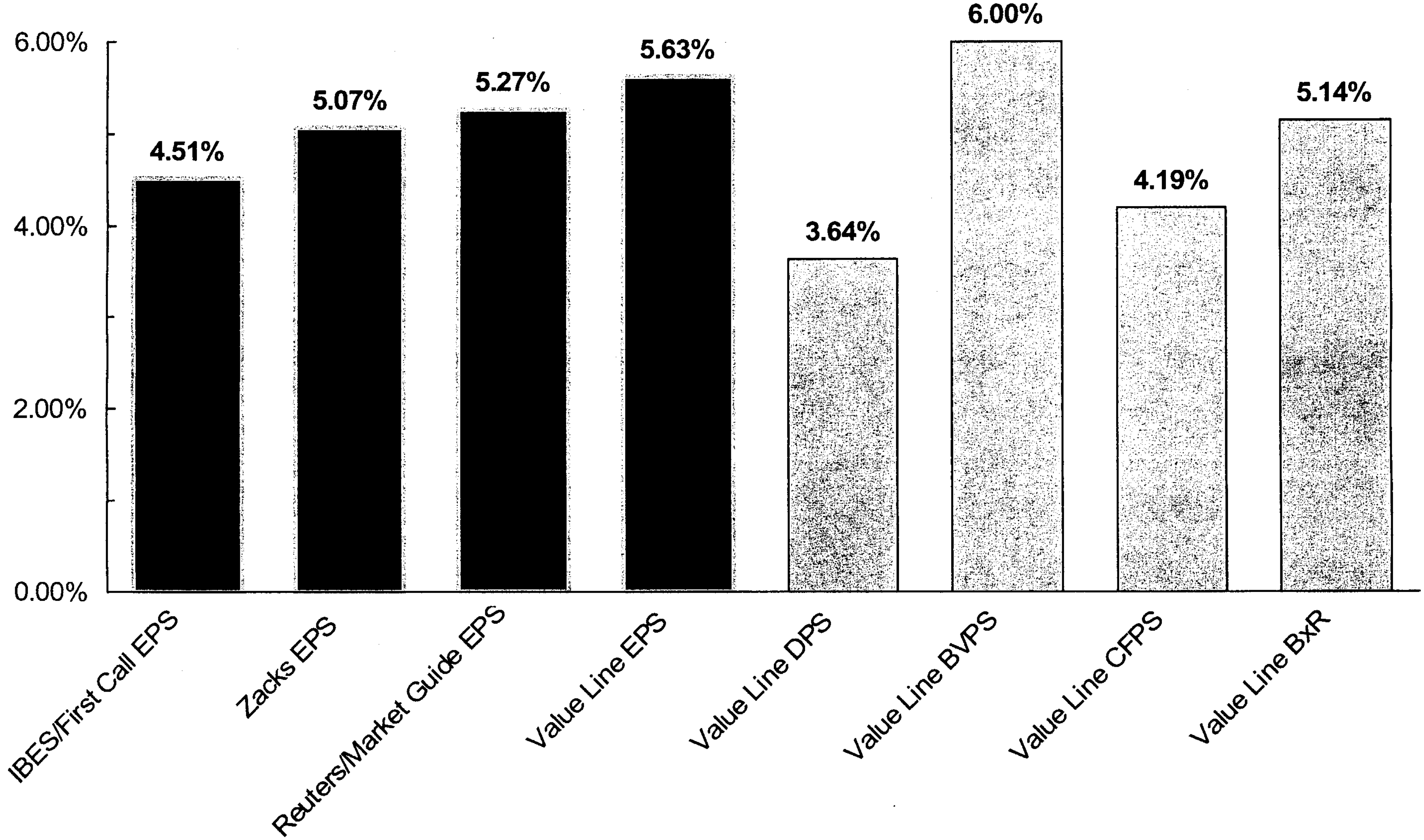
Electric Group
Historical Growth Rates



Earnings per Share=EPS Book Values per Share=BVPS
Dividends per Share=DPS Cash Flow per Share=CFPS
Percent Retained to Common Equity=BxR

Electric Group

Five-Year Projected Growth Rates



Earnings per Share=EPS Book Values per Share=BVPS
Dividends per Share=DPS Cash Flow per Share=CFPS
Percent Retained to Common Equity=BxR

Electric Industry
Analysis of Public Offerings of Common Stock
Years 2001-2004

	Allete	CMS Energy	TECO Energy	Utilicorp United	Duke Energy	Constellation Energy	Black Hills Corp.	Allegheny Energy	WPS Resources	Progress Energy	Sierra Pacific
Date of Offering	1/24/2001	2/23/2001	3/6/2001	3/9/2001	3/13/2001	3/21/2001	4/18/2001	4/26/2001	5/2/2001	8/14/2001	8/15/2001
No. of shares offered (000)	6,500	10,000	7,500	10,000	25,000	12,000	3,000	12,400	2,000	11,000	20,500
Dollar amt. of offering ($000)	$ 153,920	$ 297,500	$ 208,125	$ 297,600	$ 974,500	$ 478,800	$ 156,000	$ 598,300	$ 68,720	$ 440,000	$ 307,500
Price to public	$ 23.680	$ 29.750	$ 27.750	$ 29.760	$ 38.980	$ 39.900	$ 52.000	$ 48.250	$ 34.360	$ 40.000	$ 15.000
Underwriter's discounts and commission	$ 0.947	$ 0.190	$ 0.832	$ 0.820	$ 1.033	$ 0.620	$ 2.860	$ 1.450	$ 1.200	$ 1.400	$ 0.820
Gross Proceeds	$ 22.733	$ 29.560	$ 26.918	$ 28.940	$ 37.947	$ 39.280	$ 49.140	$ 46.800	$ 33.160	$ 38.600	$ 14.180
Estimated company issuance expenses	$ 0.054	NA	$ 0.035	NA	$ 0.010	$ 0.022	NA	NA	NA	NA	$ 0.020
Net proceeds to company per share	$ 22.679	$ 29.560	$ 26.883	$ 28.940	$ 37.937	$ 39.258	$ 49.140	$ 46.800	$ 33.160	$ 38.600	$ 14.160
Underwriter's discount as a percent of offering price	4.0%	0.6%	3.0%	2.8%	2.7%	1.6%	5.5%	3.0%	3.5%	3.5%	5.5%
Issuance expense as a percent of offering price	0.2%	NA	0.1%	NA	0.0%	0.1%	NA	NA	NA	NA	0.1%
Total Issuance and selling expense as as a percent of offering price	4.2%	0.6%	3.1%	2.8%	2.7%	1.7%	5.5%	3.0%	3.5%	3.5%	5.6%

	Alliant Energy	Hawaiian Electric	Empire District	FPL Group	XCEL Energy	Dominion Resources	Cleco Corp	Empire District	TXU Corp.	DQE	DTE Energy
Date of Offering	11/15/2001	11/19/2001	12/4/2001	1/29/2002	2/28/2002	3/13/2002	5/2/2002	5/16/2002	5/31/2002	6/20/2002	6/19/2002
No. of shares offered (000)	8,500	1,500	1,750	10,000	20,000	9,400	1,750	2,500	11,000	15,000	5,500
Dollar amt. of offering ($000)	$ 238,000	$ 56,550	$ 35,648	$ 500,000	$ 450,000	$ 562,120	$ 57,750	$ 51,875	$ 562,650	$ 202,500	$ 237,875
Price to public	$ 28.000	$ 37.700	$ 20.370	$ 50.000	$ 22.500	$ 59.800	$ 33.000	$ 20.750	$ 51.150	$ 13.500	$ 43.250
Underwriter's discounts and commission	$ 1.050	$ 1.510	$ 0.870	$ 1.500	$ 0.730	NA	$ 0.850	$ 0.882	$ 1.535	$ 0.506	$ 1.406
Gross Proceeds	$ 26.950	$ 36.190	$ 19.500	$ 48.500	$ 21.770	$ 59.800	$ 32.150	$ 19.868	$ 49.615	$ 12.994	$ 41.844
Estimated company issuance expenses	$ 0.050	NA	NA	$ 0.075	$ 0.015	$ 0.021	$ 0.114	NA	$ 0.020	$ 0.033	$ 0.045
Net proceeds to company per share	$ 26.900	$ 36.190	$ 19.500	$ 48.425	$ 21.755	$ 59.779	$ 32.150	$ 19.868	$ 49.595	$ 12.961	$ 41.799
Underwriter's discount as a percent of offering price	3.8%	4.0%	4.3%	3.0%	3.2%	NA	2.6%	4.3%	3.0%	3.7%	3.3%
Issuance expense as a percent of offering price	0.2%	NA	NA	0.2%	0.1%	0.0%	0.3%	NA	0.0%	0.2%	0.1%
Total Issuance and selling expense as as a percent of offering price	4.0%	4.0%	4.3%	3.2%	3.3%	0.0%	2.9%	4.3%	3.0%	3.9%	3.4%

	Teco Energy	American Electric	Ameren	PPL Corp	Duke Energy	Dominion Resources	Teco Energy	Pudget Energy	PSE&G	Pudget Energy	TXU Corp.
Date of Offering	6/4/2002	6/5/2002	9/10/2002	9/12/2002	9/25/2002	10/15/2002	10/10/2002	10/31/2002	11/12/2002	11/5/2002	11/25/2002
No. of shares offered (000)	13,500	16,000	7,000	14,500	54,500	26,500	17,000	5,000	15,000	5,000	30,500
Dollar amt. of offering ($000)	$ 310,500	$ 654,400	$ 294,000	$ 442,250	$ 1,000,075	$ 1,073,250	$ 187,000	$ 103,500	$ 398,250	$ 103,500	$ 450,485
Price to public	$ 23.000	$ 40.900	$ 42.000	$ 30.500	$ 18.350	$ 40.500	$ 11.000	$ 20.700	$ 27.000	$ 21.000	$ 14.770
Underwriter's discounts and commission	$ 0.690	$ 1.227	$ 1.370	$ 0.961	$ 0.459	NA	$ 0.330	$ 0.700	$ 1.000	$ 1.000	$ 0.479
Gross Proceeds	$ 22.310	$ 39.673	$ 40.630	$ 29.539	$ 17.891	$ 40.500	$ 10.670	$ 20.000	$ 26.000	$ 20.000	$ 14.291
Estimated company issuance expenses	NA	$ 0.023	$ 0.057	$ 0.034	$ 0.018	$ 0.013	$ 0.011	$ 0.025	$ 0.023	$ 0.025	$ 0.013
Net proceeds to company per share	$ 22.310	$ 39.650	$ 40.573	$ 29.505	$ 17.873	$ 40.487	$ 10.659	$ 19.975	$ 25.977	$ 19.975	$ 14.278
Underwriter's discount as a percent of offering price	3.0%	3.0%	3.3%	3.2%	2.5%	NA	3.0%	3.4%	3.7%	4.8%	3.2%
Issuance expense as a percent of offering price	NA	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%
Total Issuance and selling expense as as a percent of offering price	3.0%	3.1%	3.4%	3.3%	2.6%	0.0%	3.1%	3.5%	3.8%	4.9%	3.3%

Electric Industry
Analysis of Public Offerings of Common Stock
Years 2001-2004

	Great Plains	Progress Energy	PEPCO Holdings	Ameren	Cinergy	American Electric	PPL Corp.	Consolidated Edison	OGE Corp	TECO Energy
Date of Offering	11/21/2002	11/6/2002	12/10/2002	1/14/2003	1/31/2003	2/27/2003	5/15/2003	5/16/2003	8/21/2003	9/10/2003
No. of shares offered (000)	6,000	14,670	5,000	5,500	5,700	56,158	65,000	87,000	4,650	11,000
Dollar amt. of offering ($000)	$ 132,000	$ 614,673	$ 91,920	$ 222,750	$ 177,270	$ 1,176,514	$ 2,486,251	$ 3,462,600	$ 100,440	$ 129,360
Price to public	$ 22.000	$ 41.900	$ 19.130	$ 40.500	$ 31.100	$ 20.950	$ 38.470	$ 39.800	$ 21.900	$ 12.500
Underwriter's discounts and commission	$ 0.825	$ 1.000	$ 0.746	$ 1.320	$ 0.250	$ 0.629	$ 1.243	$ 0.345	$ 0.790	NA
Gross Proceeds	$ 21.175	$ 40.900	$ 18.384	$ 39.180	$ 30.850	$ 20.321	$ 37.227	$ 39.455	$ 21.110	$ 12.500
Estimated company issuance expenses	NA	$ 0.043	$ 0.070	$ 0.073	$ 0.035	$ 0.010	$ 0.006	$ 0.004	NA	NA
Net proceeds to company per share	$ 21.175	$ 40.857	$ 18.314	$ 39.107	$ 30.815	$ 20.311	$ 37.221	$ 39.451	$ 21.110	$ 12.500
Underwriter's discount as a percent of offering price	3.8%	2.4%	3.9%	3.3%	0.8%	3.0%	3.2%	0.9%	3.6%	NA
Issuance expense as a percent of offering price	NA	0.1%	0.4%	0.2%	0.1%	0.0%	0.0%	0.0%	NA	NA
Total Issuance and selling expense as as a percent of offering price	3.8%	2.5%	4.3%	3.5%	0.9%	3.0%	3.2%	0.9%	3.6%	NA

	First Energy	PSEG	Unitil	Pudget Energy	WPS Resources	Empire District	Hawaiian Electric	ConEdison	Great Plains	Constellation
Date of Offering	9/12/2003	10/1/2003	10/21/2003	10/31/2003	11/19/2003	12/11/2003	3/10/2004	4/11/2004	6/8/2004	6/28/2004
No. of shares offered (000)	28,000	8,250	6,524	4,550	3,500	2,000	2,000	14,000	6,000	6,000
Dollar amt. of offering ($000)	$ 840,000	$ 344,438	$ 165,710	$ 103,513	$ 150,500	$ 42,300	$ 103,720	$ 528,360	$ 150,000	$ 227,700
Price to public	$ 30.000	$ 41.750	$ 25.400	$ 22.750	$ 43.000	$ 21.290	$ 51.860	$ 37.750	$ 25.000	$ 37.950
Underwriter's discounts and commission	$ 0.975	$ 1.253	$ 1.270	$ 0.750	$ 0.798	$ 0.900	$ 2.074	$ 1.132	$ 0.750	$ 0.140
Gross Proceeds	$ 29.025	$ 40.497	$ 24.130	$ 22.000	$ 42.202	$ 20.390	$ 49.786	$ 36.618	$ 24.250	$ 37.810
Estimated company issuance expenses	$ 0.015	$ 0.042	NA	NA	NA	NA	$ 0.075	$ 0.029	$ 0.083	$ 0.042
Net proceeds to company per share	$ 29.010	$ 40.455	$ 24.130	$ 22.000	$ 42.202	$ 20.390	$ 49.711	$ 36.589	$ 24.167	$ 37.768
Underwriter's discount as a percent of offering price	3.3%	3.0%	5.0%	3.3%	1.9%	4.2%	4.0%	3.0%	3.0%	0.4%
Issuance expense as a percent of offering price	0.1%	0.1%	NA	NA	NA	NA	0.1%	0.1%	0.3%	0.1%
Total Issuance and selling expense as as a percent of offering price	3.4%	3.1%	5.0%	3.3%	1.9%	4.2%	4.1%	3.1%	3.3%	0.5%

	Ameren	CMS Energy	Ottertail	Idacorp	Cinergy	Average
Date of Offering	6/30/2004	10/7/2004	12/7/2004	12/9/2004	12/15/2004	
No. of shares offered (000)	10,000	28,500	2,900	3,500	6,100	
Dollar amt. of offering ($000)	$ 420,000	$ 259,350	$ 73,805	$ 105,000	$ 250,100	
Price to public	$ 42.000	$ 9.100	$ 25.450	$ 30.000	$ 41.000	
Underwriter's discounts and commission	$ 1.260	$ 0.319	$ 0.950	$ 1.200	$ 0.490	
Gross Proceeds	$ 40.740	$ 8.781	$ 24.500	$ 28.800	$ 40.510	
Estimated company issuance expenses	$ 0.040	$ 0.011	$ 0.103	$ 0.086	$ 0.033	
Net proceeds to company per share	$ 40.700	$ 8.770	$ 24.397	$ 28.714	$ 40.477	
Underwriter's discount as a percent of offering price	3.0%	3.5%	3.7%	4.0%	1.2%	3.2%
Issuance expense as a percent of offering price	0.1%	0.1%	0.4%	0.3%	0.1%	0.1%
Total Issuance and selling expense as as a percent of offering price	3.1%	3.6%	4.1%	4.3%	1.3%	3.3%

Source of Information: Public Utility Financing Tracker

Return on Common Equity Calculation

Company	Low Dividend Yield (D/P)	High Dividend Yield (D/P)	"b times r" + "s times v" Adjusted Div. Yield (D1/P)	+	Growth Rate (g)	=	Low Cost of Equity (K)	"b times r" + "s times v" Adjusted Div. Yield (D1/P)	+	Growth Rate (g)	=	High Cost of Equity (K)
AMEREN CORP (NYSE:AEE)	4.82%	5.11%	4.87%	+	2.21%	=	7.08%	5.16%	+	2.21%	=	7.37%
DTE ENERGY CO (NYSE:DTE)	4.44%	4.68%	4.55%	+	4.80%	=	9.35%	4.80%	+	4.80%	=	9.60%
EXELON CORP (NYSE:EXC)	3.33%	3.63%	3.50%	+	9.94%	=	13.44%	3.81%	+	9.94%	=	13.75%
FIRSTENERGY CORP (NYSE:FE)	3.80%	4.06%	3.90%	+	5.45%	=	9.35%	4.17%	+	5.45%	=	9.62%
MGE ENERGY INC (NASDAQ-NM:MGE	3.77%	4.17%	3.84%	+	3.67%	=	7.51%	4.24%	+	3.67%	=	7.91%
VECTREN CORP (NYSE:VVC)	4.23%	4.50%	4.32%	+	3.99%	=	8.31%	4.59%	+	3.99%	=	8.58%
WPS RES CORP (NYSE:WPS)	4.07%	4.33%	4.21%	+	6.57%	=	10.78%	4.47%	+	6.57%	=	11.04%
WISCONSIN ENERGY CORP (NYSE:W	2.43%	2.56%	2.50%	+	6.40%	=	8.90%	2.64%	+	6.40%	=	9.04%

Company	Low Dividend Yield (D/P)	High Dividend Yield (D/P)	IBES/ First Call Adjusted Div. Yield (D1/P)	+	Growth Rate (g)	=	Low Cost of Equity (K)	IBES/ First Call Adjusted Div. Yield (D1/P)	+	Growth Rate (g)	=	High Cost of Equity (K)
AMEREN CORP (NYSE:AEE)	4.82%	5.11%	4.90%	+	3.36%	=	8.26%	5.19%	+	3.36%	=	8.55%
DTE ENERGY CO (NYSE:DTE)	4.44%	4.68%	4.53%	+	4.20%	=	8.73%	4.78%	+	4.20%	=	8.98%
EXELON CORP (NYSE:EXC)	3.33%	3.63%	3.42%	+	5.29%	=	8.71%	3.72%	+	5.29%	=	9.01%
FIRSTENERGY CORP (NYSE:FE)	3.80%	4.06%	3.88%	+	4.20%	=	8.08%	4.15%	+	4.20%	=	8.35%
MGE ENERGY INC (NASDAQ-NM:MGE	3.77%	4.17%		+	-	=			+	-	=	
VECTREN CORP (NYSE:VVC)	4.23%	4.50%	4.32%	+	4.00%	=	8.32%	4.59%	+	4.00%	=	8.59%
WPS RES CORP (NYSE:WPS)	4.07%	4.33%	4.16%	+	4.33%	=	8.49%	4.42%	+	4.33%	=	8.75%
WISCONSIN ENERGY CORP (NYSE:W	2.43%	2.56%	2.50%	+	6.20%	=	8.70%	2.64%	+	6.20%	=	8.84%

Zone of Reasonableness

Company	Low	High
AMEREN CORP (NYSE:AEE)		8.55%
DTE ENERGY CO (NYSE:DTE)	8.73%	9.60%
EXELON CORP (NYSE:EXC)	8.71%	13.75%
FIRSTENERGY CORP (NYSE:FE)	8.08%	9.62%
MGE ENERGY INC (NASDAQ-NM:MGEE)		
VECTREN CORP (NYSE:VVC)	8.31%	8.59%
WPS RES CORP (NYSE:WPS)	8.49%	11.04%
WISCONSIN ENERGY CORP (NYSE:WEC)	8.70%	9.04%
Range	**8.08%** (1)	**13.75%**

Midpoint **10.92%**

Note: (1) Removed values less than 8.00%, based on FERC's reasoning that "investors generally cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low end-return cannot be considered reliable."

Source of Model: Opinion No. 445 (92 FERC ¶ 61,070)
Opinion No. 456 (98 FERC ¶ 61,333)

Dividend Yield Calculations

Company	Mo/Yr	Price High	Price Low	Indicated Dividend Rate	Dividend Yield High	Dividend Yield Low
AMEREN CORP (NYSE:AEE)	Jan-05	$50.26	$48.17	$ 2.54	5.27%	5.05%
	Feb-05	$51.96	$49.80	$ 2.54	5.10%	4.89%
	Mar-05	$52.00	$47.51	$ 2.54	5.35%	4.88%
	Apr-05	$51.70	$48.70	$ 2.54	5.22%	4.91%
	May-05	$54.97	$51.66	$ 2.54	4.92%	4.62%
	Jun-05	$55.84	$53.28	$ 2.54	4.77%	4.55%
Average					5.11%	4.82%
DTE ENERGY CO (NYSE:DTE)	Jan-05	$44.00	$42.40	$ 2.06	4.86%	4.68%
	Feb-05	$45.05	$43.01	$ 2.06	4.79%	4.57%
	Mar-05	$46.99	$43.36	$ 2.06	4.75%	4.38%
	Apr-05	$46.38	$44.40	$ 2.06	4.64%	4.44%
	May-05	$47.71	$44.77	$ 2.06	4.60%	4.32%
	Jun-05	$48.31	$46.15	$ 2.06	4.46%	4.26%
Average					4.68%	4.44%
EXELON CORP (NYSE:EXC)	Jan-05	$44.47	$41.77	$ 1.60	3.83%	3.60%
	Feb-05	$46.20	$43.32	$ 1.60	3.69%	3.46%
	Mar-05	$47.18	$43.69	$ 1.60	3.66%	3.39%
	Apr-05	$49.55	$45.14	$ 1.60	3.54%	3.23%
	May-05	$49.70	$44.14	$ 1.60	3.62%	3.22%
	Jun-05	$52.01	$46.91	$ 1.60	3.41%	3.08%
Average					3.63%	3.33%
FIRSTENERGY CORP (NYSE:FE)	Jan-05	$40.13	$37.70	$ 1.65	4.38%	4.11%
	Feb-05	$41.98	$39.61	$ 1.65	4.17%	3.93%
	Mar-05	$42.36	$39.81	$ 1.65	4.14%	3.90%
	Apr-05	$43.66	$40.75	$ 1.65	4.05%	3.78%
	May-05	$44.56	$42.35	$ 1.65	3.90%	3.70%
	Jun-05	$48.96	$44.25	$ 1.65	3.73%	3.37%
Average					4.06%	3.80%
MGE ENERGY INC (NASDAQ-NM:MGE	Jan-05	$36.44	$33.28	$ 1.37	4.12%	3.76%
	Feb-05	$37.23	$34.51	$ 1.37	3.97%	3.68%
	Mar-05	$36.52	$32.37	$ 1.37	4.23%	3.75%
	Apr-05	$33.68	$30.50	$ 1.37	4.49%	4.07%
	May-05	$36.44	$31.94	$ 1.37	4.29%	3.76%
	Jun-05	$37.91	$35.00	$ 1.37	3.91%	3.61%
Average					4.17%	3.77%
VECTREN CORP (NYSE:VVC)	Jan-05	$27.61	$25.84	$ 1.18	4.57%	4.27%
	Feb-05	$27.95	$26.27	$ 1.18	4.49%	4.22%
	Mar-05	$27.92	$25.82	$ 1.18	4.57%	4.23%
	Apr-05	$27.45	$26.16	$ 1.18	4.51%	4.30%
	May-05	$27.45	$26.01	$ 1.18	4.54%	4.30%
	Jun-05	$28.98	$27.35	$ 1.18	4.31%	4.07%
Average					4.50%	4.23%
WPS RES CORP (NYSE:WPS)	Jan-05	$51.34	$47.67	$ 2.22	4.66%	4.32%
	Feb-05	$54.00	$50.60	$ 2.22	4.39%	4.11%
	Mar-05	$54.90	$51.62	$ 2.22	4.30%	4.04%
	Apr-05	$54.00	$51.11	$ 2.22	4.34%	4.11%
	May-05	$56.23	$52.54	$ 2.22	4.23%	3.95%
	Jun-05	$56.90	$54.74	$ 2.22	4.06%	3.90%
Average					4.33%	4.07%
WISCONSIN ENERGY CORP (NYSE:W	Jan-05	$34.50	$33.35	$ 0.88	2.64%	2.55%
	Feb-05	$36.12	$34.19	$ 0.88	2.57%	2.44%
	Mar-05	$35.79	$34.01	$ 0.88	2.59%	2.46%
	Apr-05	$35.93	$34.66	$ 0.88	2.54%	2.45%
	May-05	$36.42	$34.20	$ 0.88	2.57%	2.42%
	Jun-05	$39.31	$36.25	$ 0.88	2.43%	2.24%
Average					2.56%	2.43%

Source of Information: Standard & Poor's Security Owner's Stock Guide

"b times r" Growth Rate

Company	Value Line Return on Com. Equity	Common Equity 2006	Common Equity 2008-10	Growth	Adjustment Factor	Average Yearly Return	"b times r" Growth Rate
AMEREN CORP (NYSE:AEE)	9.33%	$6,320	$7,059	3.75%	1.0184	9.50%	1.67%
DTE ENERGY CO (NYSE:DTE)	11.00%	$5,957	$6,717	4.08%	1.0200	11.22%	5.15%
EXELON CORP (NYSE:EXC)	18.00%	$11,844	$16,357	11.36%	1.0537	18.97%	9.01%
FIRSTENERGY CORP (NYSE:FE)	11.17%	$9,665	$11,550	6.12%	1.0297	11.50%	5.45%
MGE ENERGY INC (NASDAQ-NM:MGE	10.83%	$356	$384	2.56%	1.0126	10.97%	3.66%
VECTREN CORP (NYSE:VVC)	11.67%	$1,189	$1,338	4.01%	1.0197	11.90%	3.82%
WPS RES CORP (NYSE:WPS)	12.50%	$1,254	$1,523	6.69%	1.0324	12.91%	5.82%
WISCONSIN ENERGY CORP (NYSE:WI	10.00%	$2,832	$3,412	6.41%	1.0311	10.31%	6.40%
Average	11.81%			5.62%	1.0272	12.16%	5.12%

"s times v" Growth Rate

Company	2004 Book Value per Share	Six-Month Average Stock Price	1-(B/P)	Common Shares Outst'g 2004	Common Shares Outst'g 2008-10	Growth	"s times v" Growth Rate
AMEREN CORP (NYSE:AEE)	$30.15	$51.32	0.4125	195.00	208.00	1.30%	0.54%
DTE ENERGY CO (NYSE:DTE)	$31.85	$45.21	0.2955	174.21	164.00	-1.20%	-0.35%
EXELON CORP (NYSE:EXC)	$14.19	$46.17	0.6927	664.20	710.00	1.34%	0.93%
FIRSTENERGY CORP (NYSE:FE)	$26.04	$42.18	0.3826	329.84	329.84	0.00%	0.00%
MGE ENERGY INC (NASDAQ-NM:MGE	$16.59	$34.65	0.5212	20.39	20.40	0.01%	0.01%
VECTREN CORP (NYSE:VVC)	$14.45	$27.07	0.4661	76.00	77.40	0.37%	0.17%
WPS RES CORP (NYSE:WPS)	$29.00	$52.97	0.4525	37.40	40.60	1.66%	0.75%
WISCONSIN ENERGY CORP (NYSE:WI	$21.31	$35.39	0.3979	116.99	117.00	0.00%	0.00%
Average			0.4526			0.44%	0.25%

Source of Information: The Value Line Investment Survey, April 1, 2005, and June 3, 2005

Retention Growth Components

Company	2005 DPS	2005 EPS	2005 Dividend Payout	2005 Return on Com. Equity
AMEREN CORP (NYSE:AEE)	$2.54	$3.00	84.67%	9.50%
DTE ENERGY CO (NYSE:DTE)	$2.06	$3.30	62.42%	10.00%
EXELON CORP (NYSE:EXC)	$1.60	$3.05	52.46%	19.50%
FIRSTENERGY CORP (NYSE:FE)	$1.65	$2.85	57.89%	10.50%
MGE ENERGY INC (NASDAQ-NM:MGE	$1.37	$1.90	72.11%	10.00%
VECTREN CORP (NYSE:VVC)	$1.19	$1.75	68.00%	11.50%
WPS RES CORP (NYSE:WPS)	$2.24	$4.10	54.63%	13.00%
WISCONSIN ENERGY CORP (NYSE:W	$0.88	$2.30	38.26%	10.50%
Average			61.31%	11.81%

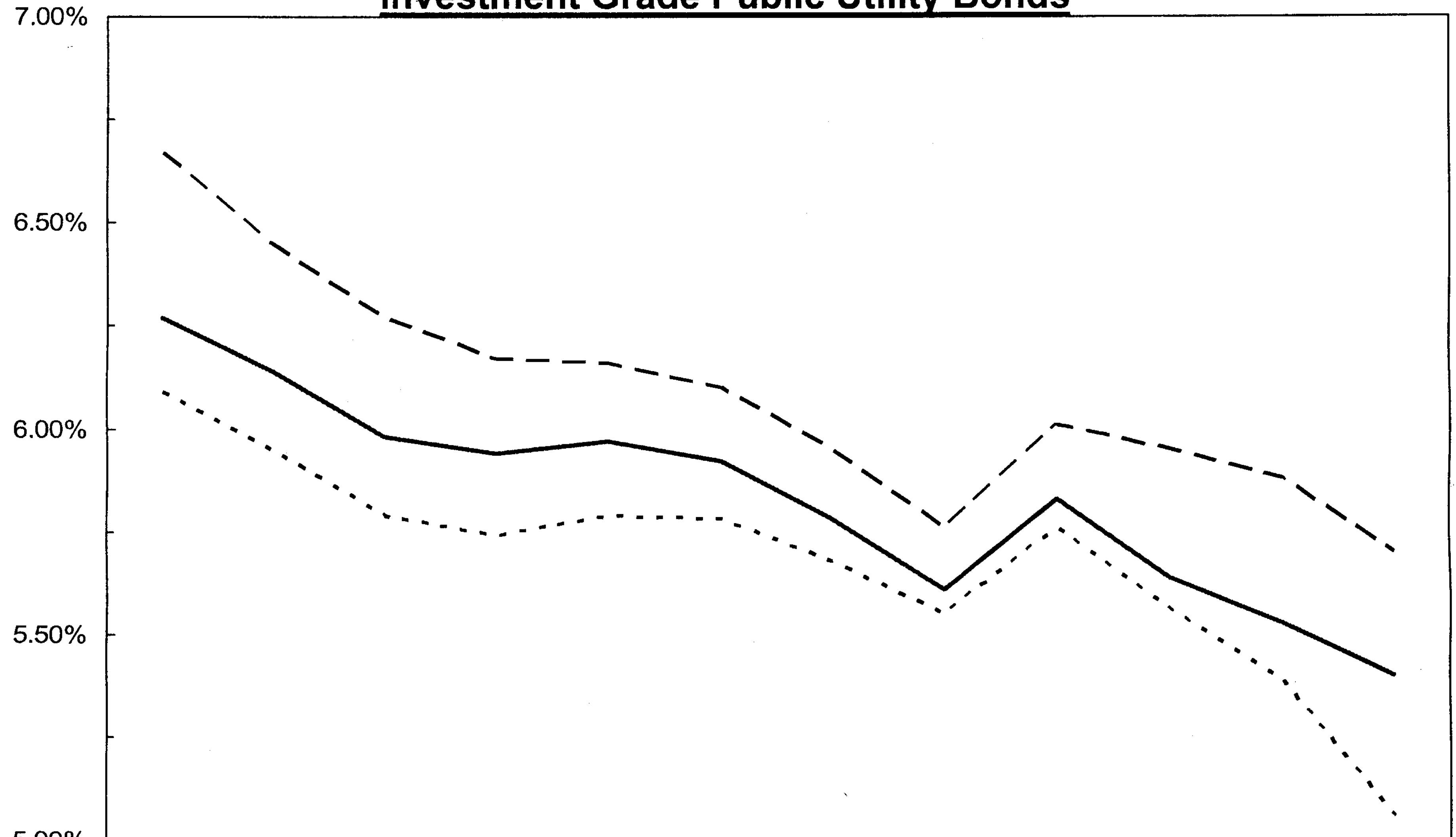
Company	2006 DPS	2006 EPS	2006 Dividend Payout	2006 Return on Com. Equity
AMEREN CORP (NYSE:AEE)	$2.54	$3.10	81.94%	9.50%
DTE ENERGY CO (NYSE:DTE)	$2.06	$3.70	55.68%	11.00%
EXELON CORP (NYSE:EXC)	$1.68	$3.20	52.50%	18.50%
FIRSTENERGY CORP (NYSE:FE)	$1.72	$3.45	49.86%	11.50%
MGE ENERGY INC (NASDAQ-NM:MGE	$1.38	$2.00	69.00%	10.50%
VECTREN CORP (NYSE:VVC)	$1.23	$1.85	66.49%	12.00%
WPS RES CORP (NYSE:WPS)	$2.28	$4.20	54.29%	13.00%
WISCONSIN ENERGY CORP (NYSE:W	$0.92	$2.45	37.55%	10.00%
Average			58.41%	12.00%

Company	2008-10 DPS	2008-10 EPS	2008-10 Dividend Payout	2008-10 Return on Com. Equity
AMEREN CORP (NYSE:AEE)	$2.54	$3.15	80.63%	9.00%
DTE ENERGY CO (NYSE:DTE)	$2.10	$4.75	44.21%	12.00%
EXELON CORP (NYSE:EXC)	$1.92	$3.65	52.60%	16.00%
FIRSTENERGY CORP (NYSE:FE)	$2.00	$4.00	50.00%	11.50%
MGE ENERGY INC (NASDAQ-NM:MGE	$1.44	$2.45	58.78%	12.00%
VECTREN CORP (NYSE:VVC)	$1.35	$1.95	69.23%	11.50%
WPS RES CORP (NYSE:WPS)	$2.40	$4.30	55.81%	11.50%
WISCONSIN ENERGY CORP (NYSE:W	$1.04	$2.75	37.82%	9.50%
Average			56.14%	11.63%

Company	Average Dividend Payout	Average Return on Com. Equity
AMEREN CORP (NYSE:AEE)	82.41%	9.33%
DTE ENERGY CO (NYSE:DTE)	54.10%	11.00%
EXELON CORP (NYSE:EXC)	52.52%	18.00%
FIRSTENERGY CORP (NYSE:FE)	52.58%	11.17%
MGE ENERGY INC (NASDAQ-NM:MGEE)	66.63%	10.83%
VECTREN CORP (NYSE:VVC)	67.91%	11.67%
WPS RES CORP (NYSE:WPS)	54.91%	12.50%
WISCONSIN ENERGY CORP (NYSE:WEC)	37.88%	10.00%
Average	58.62%	11.81%

Source of Information: The Value Line Investment Survey, April 1, 2005, and June 3, 2005

Interest Rates for Investment Grade Public Utility Bonds



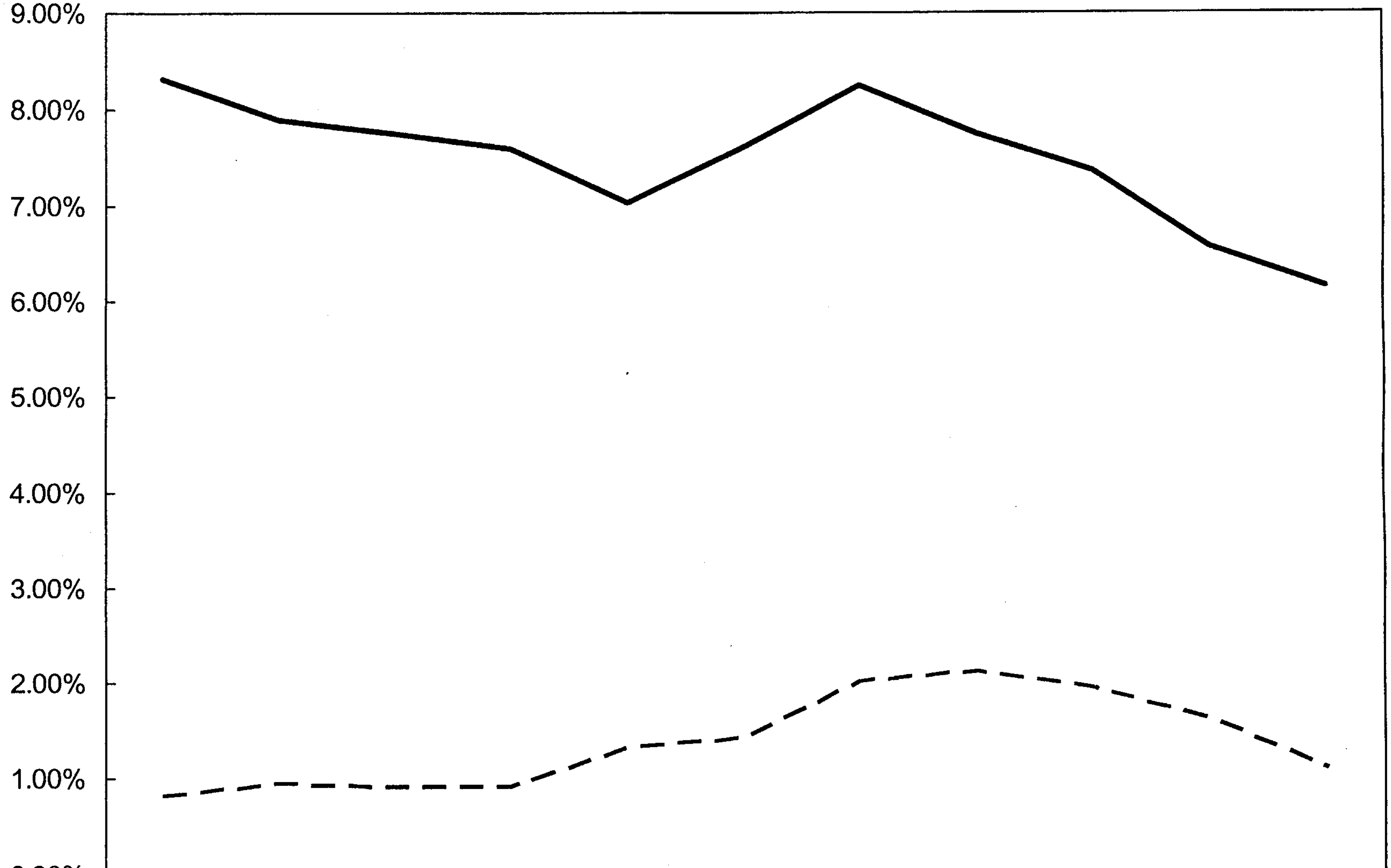
	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05
Aa	6.09%	5.95%	5.79%	5.74%	5.79%	5.78%	5.68%	5.55%	5.76%	5.56%	5.39%	5.06%
A	6.27%	6.14%	5.98%	5.94%	5.97%	5.92%	5.78%	5.61%	5.83%	5.64%	5.53%	5.40%
Baa	6.67%	6.45%	6.27%	6.17%	6.16%	6.10%	5.95%	5.76%	6.01%	5.95%	5.88%	5.70%

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2000-2004
and the Twelve Months Ended June 2005

Years	Aa Rated	A Rated	Baa Rated	Average
2000	8.06%	8.24%	8.36%	8.14%
2001	7.58%	7.76%	8.03%	7.72%
2002	7.19%	7.37%	8.02%	7.53%
2003	6.40%	6.58%	6.84%	6.61%
2004	6.04%	6.16%	6.40%	6.20%
Five-Year Average	7.05%	7.22%	7.53%	7.24%
Months				
Jul-04	6.09%	6.27%	6.67%	6.34%
Aug-04	5.95%	6.14%	6.45%	6.18%
Sep-04	5.79%	5.98%	6.27%	6.01%
Oct-04	5.74%	5.94%	6.17%	5.95%
Nov-04	5.79%	5.97%	6.16%	5.97%
Dec-04	5.78%	5.92%	6.10%	5.93%
Jan-05	5.68%	5.78%	5.95%	5.80%
Feb-05	5.55%	5.61%	5.76%	5.64%
Mar-05	5.76%	5.83%	6.01%	5.86%
Apr-05	5.56%	5.64%	5.95%	5.72%
May-05	5.39%	5.53%	5.88%	5.60%
Jun-05	5.06%	5.40%	5.70%	5.39%
Twelve-Month Average	5.68%	5.83%	6.09%	5.87%
Six-Month Average	5.50%	5.63%	5.88%	5.67%
Three-Month Average	5.34%	5.52%	5.84%	5.57%

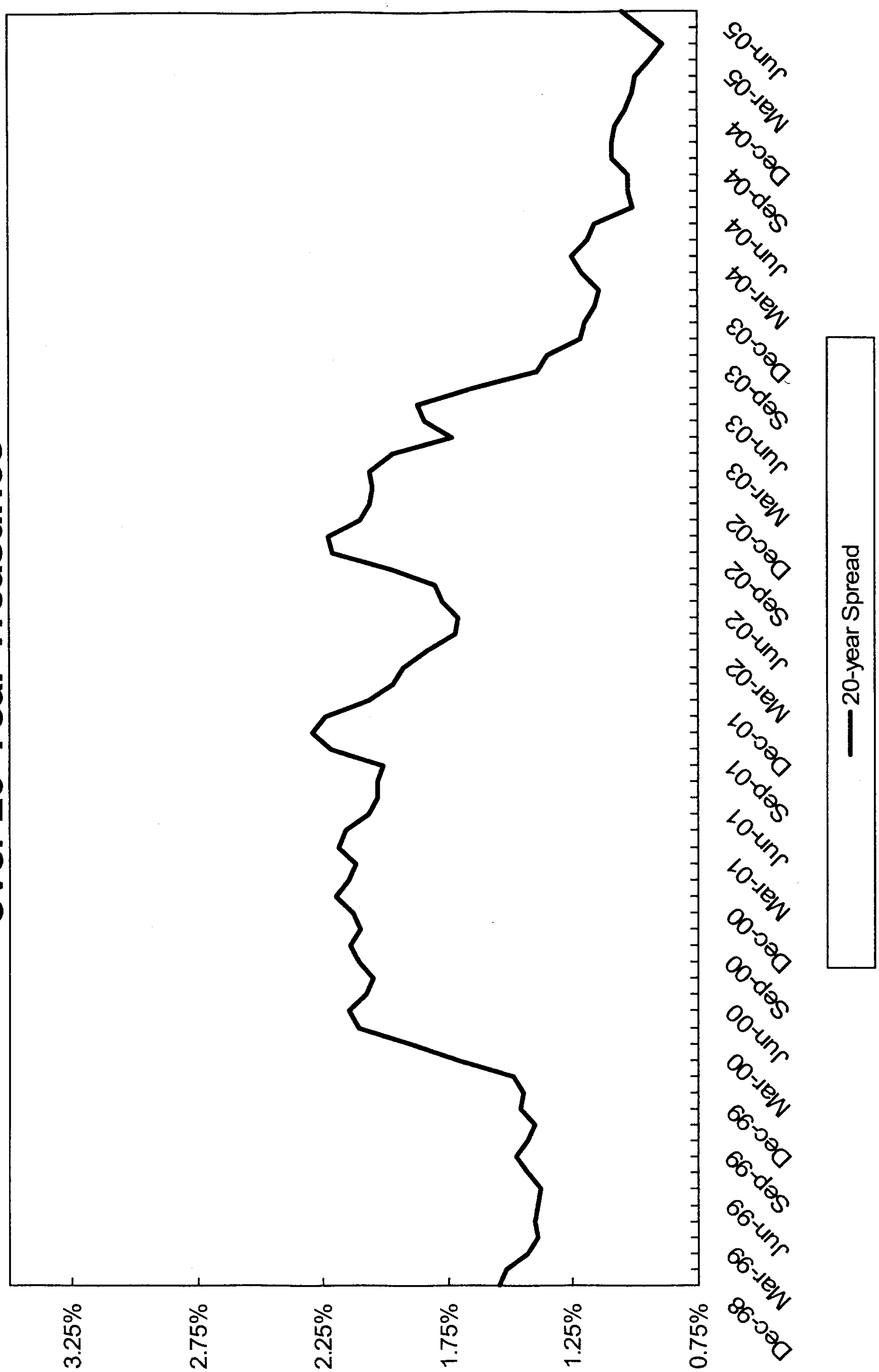
Source: Mergent Bond Record

Yields on A-rated Public Utility Bonds and Spreads over 20-Year Treasuries



	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
A-rated Public Utility	8.31%	7.89%	7.75%	7.60%	7.04%	7.62%	8.24%	7.76%	7.37%	6.58%	6.16%
Spread vs. 20-year	0.82%	0.94%	0.92%	0.91%	1.32%	1.42%	2.01%	2.13%	1.94%	1.62%	1.11%

Interest Rate Spreads
A-rated Public Utility Bonds
over 20-Year Treasuries



A rated Public Utility Bonds
over 20-Year Treasuries

Year	A-rated Public Utility	20-Year Treasuries Yield	20-Year Treasuries Spread
Dec-98	6.91%	5.36%	1.55%
Jan-99	6.97%	5.45%	1.52%
Feb-99	7.09%	5.66%	1.43%
Mar-99	7.26%	5.87%	1.39%
Apr-99	7.22%	5.82%	1.40%
May-99	7.47%	6.08%	1.39%
Jun-99	7.74%	6.36%	1.38%
Jul-99	7.71%	6.28%	1.43%
Aug-99	7.91%	6.43%	1.48%
Sep-99	7.93%	6.50%	1.43%
Oct-99	8.06%	6.66%	1.40%
Nov-99	7.94%	6.48%	1.46%
Dec-99	8.14%	6.69%	1.45%
Jan-00	8.35%	6.86%	1.49%
Feb-00	8.25%	6.54%	1.71%
Mar-00	8.28%	6.38%	1.90%
Apr-00	8.29%	6.18%	2.11%
May-00	8.70%	6.55%	2.15%
Jun-00	8.36%	6.28%	2.08%
Jul-00	8.25%	6.20%	2.05%
Aug-00	8.13%	6.02%	2.11%
Sep-00	8.23%	6.09%	2.14%
Oct-00	8.14%	6.04%	2.10%
Nov-00	8.11%	5.98%	2.13%
Dec-00	7.84%	5.64%	2.20%
Jan-01	7.80%	5.65%	2.15%
Feb-01	7.74%	5.62%	2.12%
Mar-01	7.68%	5.49%	2.19%
Apr-01	7.94%	5.78%	2.16%
May-01	7.99%	5.92%	2.07%
Jun-01	7.85%	5.82%	2.03%
Jul-01	7.78%	5.75%	2.03%
Aug-01	7.59%	5.58%	2.01%
Sep-01	7.75%	5.53%	2.22%
Oct-01	7.63%	5.34%	2.29%
Nov-01	7.57%	5.33%	2.24%
Dec-01	7.83%	5.76%	2.07%
Jan-02	7.66%	5.69%	1.97%
Feb-02	7.54%	5.61%	1.93%
Mar-02	7.76%	5.93%	1.83%
Apr-02	7.57%	5.85%	1.72%
May-02	7.52%	5.81%	1.71%
Jun-02	7.42%	5.65%	1.77%
Jul-02	7.31%	5.51%	1.80%
Aug-02	7.17%	5.19%	1.98%
Sep-02	7.08%	4.87%	2.21%
Oct-02	7.23%	5.00%	2.23%
Nov-02	7.14%	5.04%	2.10%
Dec-02	7.07%	5.01%	2.06%
Jan-03	7.07%	5.02%	2.05%
Feb-03	6.93%	4.87%	2.06%
Mar-03	6.79%	4.82%	1.97%
Apr-03	6.64%	4.91%	1.73%
May-03	6.36%	4.52%	1.84%
Jun-03	6.21%	4.34%	1.87%
Jul-03	6.57%	4.92%	1.65%
Aug-03	6.78%	5.39%	1.39%
Sep-03	6.56%	5.21%	1.35%
Oct-03	6.43%	5.21%	1.22%
Nov-03	6.37%	5.17%	1.20%
Dec-03	6.27%	5.11%	1.16%
Jan-04	6.15%	5.01%	1.14%
Feb-04	6.15%	4.94%	1.21%
Mar-04	5.97%	4.72%	1.25%
Apr-04	6.35%	5.16%	1.19%
May-04	6.62%	5.46%	1.16%
Jun-04	6.46%	5.45%	1.01%
Jul-04	6.27%	5.24%	1.03%
Aug-04	6.14%	5.07%	1.07%
Sep-04	5.98%	4.89%	1.09%
Oct-04	5.94%	4.85%	1.09%
Nov-04	5.97%	4.89%	1.08%
Dec-04	5.92%	4.88%	1.04%
Jan-05	5.78%	4.77%	1.01%
Feb-05	5.61%	4.61%	1.00%
Mar-05	5.83%	4.89%	0.94%
Apr-05	5.64%	4.75%	0.89%
May-05	5.53%	4.56%	0.97%
Jun-05	5.40%	4.35%	1.05%

S&P Composite Index and S&P Public Utility Index
Long-Term Corporate and Public Utility Bonds
Yearly Total Returns
1928-2004

Year	S & P Composite Index	S & P Public Utility Index	Long Term Corporate Bonds	Public Utility Bonds
1928	43.61%	57.47%	2.84%	3.08%
1929	-8.42%	11.02%	3.27%	2.34%
1930	-24.90%	-21.96%	7.98%	4.74%
1931	-43.34%	-35.90%	-1.85%	-11.11%
1932	-8.19%	-0.54%	10.82%	7.25%
1933	53.99%	-21.87%	10.38%	-3.82%
1934	-1.44%	-20.41%	13.84%	22.61%
1935	47.67%	76.63%	9.61%	16.03%
1936	33.92%	20.69%	6.74%	8.30%
1937	-35.03%	-37.04%	2.75%	-4.05%
1938	31.12%	22.45%	6.13%	8.11%
1939	-0.41%	11.26%	3.97%	6.76%
1940	-9.78%	-17.15%	3.39%	4.45%
1941	-11.59%	-31.57%	2.73%	2.15%
1942	20.34%	15.39%	2.60%	3.81%
1943	25.90%	46.07%	2.83%	7.04%
1944	19.75%	18.03%	4.73%	3.29%
1945	36.44%	53.33%	4.08%	5.92%
1946	-8.07%	1.26%	1.72%	2.98%
1947	5.71%	-13.16%	-2.34%	-2.19%
1948	5.50%	4.01%	4.14%	2.65%
1949	18.79%	31.39%	3.31%	7.16%
1950	31.71%	3.25%	2.12%	2.01%
1951	24.02%	18.63%	-2.69%	-2.77%
1952	18.37%	19.25%	3.52%	2.99%
1953	-0.99%	7.85%	3.41%	2.08%
1954	52.62%	24.72%	5.39%	7.57%
1955	31.56%	11.26%	0.48%	0.12%
1956	6.56%	5.06%	-6.81%	-6.25%
1957	-10.78%	6.36%	8.71%	3.58%
1958	43.36%	40.70%	-2.22%	0.18%
1959	11.96%	7.49%	-0.97%	-2.29%
1960	0.47%	20.26%	9.07%	9.01%
1961	26.89%	29.33%	4.82%	4.65%
1962	-8.73%	-2.44%	7.95%	6.55%
1963	22.80%	12.36%	2.19%	3.44%
1964	16.48%	15.91%	4.77%	4.94%
1965	12.45%	4.67%	-0.46%	0.50%
1966	-10.06%	-4.48%	0.20%	-3.45%
1967	23.98%	-0.63%	-4.95%	-3.63%
1968	11.06%	10.32%	2.57%	1.87%
1969	-8.50%	-15.42%	-8.09%	-6.66%
1970	4.01%	16.56%	18.37%	15.90%
1971	14.31%	2.41%	11.01%	11.59%
1972	18.98%	8.15%	7.26%	7.19%
1973	-14.66%	-18.07%	1.14%	2.42%
1974	-26.47%	-21.55%	-3.06%	-5.28%
1975	37.20%	44.49%	14.64%	15.50%
1976	23.84%	31.81%	18.65%	19.04%
1977	-7.18%	8.64%	1.71%	5.22%
1978	6.56%	-3.71%	-0.07%	-0.98%
1979	18.44%	13.58%	-4.18%	-2.75%
1980	32.42%	15.08%	-2.76%	-0.23%
1981	-4.91%	11.74%	-1.24%	4.27%
1982	21.41%	26.52%	42.56%	33.52%
1983	22.51%	20.01%	6.26%	10.33%
1984	6.27%	26.04%	16.86%	14.82%
1985	32.16%	33.05%	30.09%	26.48%
1986	18.47%	28.53%	19.85%	18.16%
1987	5.23%	-2.92%	-0.27%	3.02%
1988	16.81%	18.27%	10.70%	10.19%
1989	31.49%	47.80%	16.23%	15.61%
1990	-3.17%	-2.57%	6.78%	8.13%
1991	30.55%	14.61%	19.89%	19.25%
1992	7.67%	8.10%	9.39%	8.65%
1993	9.99%	14.41%	13.19%	10.59%
1994	1.31%	-7.94%	-5.76%	-4.72%
1995	37.43%	42.15%	27.20%	22.81%
1996	23.07%	3.14%	1.40%	3.04%
1997	33.36%	24.69%	12.95%	11.39%
1998	28.58%	14.82%	10.76%	9.44%
1999	21.04%	-8.85%	-7.45%	-1.69%
2000	-9.11%	59.70%	12.87%	9.45%
2001	-11.88%	-30.41%	10.65%	5.85%
2002	-22.10%	-30.04%	16.33%	1.63%
2003	28.70%	26.11%	5.27%	10.01%
2004	10.87%	24.22%	8.72%	6.03%
Geometric Mean	10.10%	8.55%	5.89%	5.50%
Arithmetic Mean	12.08%	10.94%	6.22%	5.79%
Standard Deviation	20.37%	22.81%	8.67%	7.98%
Median	14.31%	11.26%	4.14%	4.65%

Tabulation of Risk Rate Differentials for
S&P Public Utility Index and Public Utility Bonds
For the Years 1928-2004, 1952-2004, 1974-2004, and 1979-2004

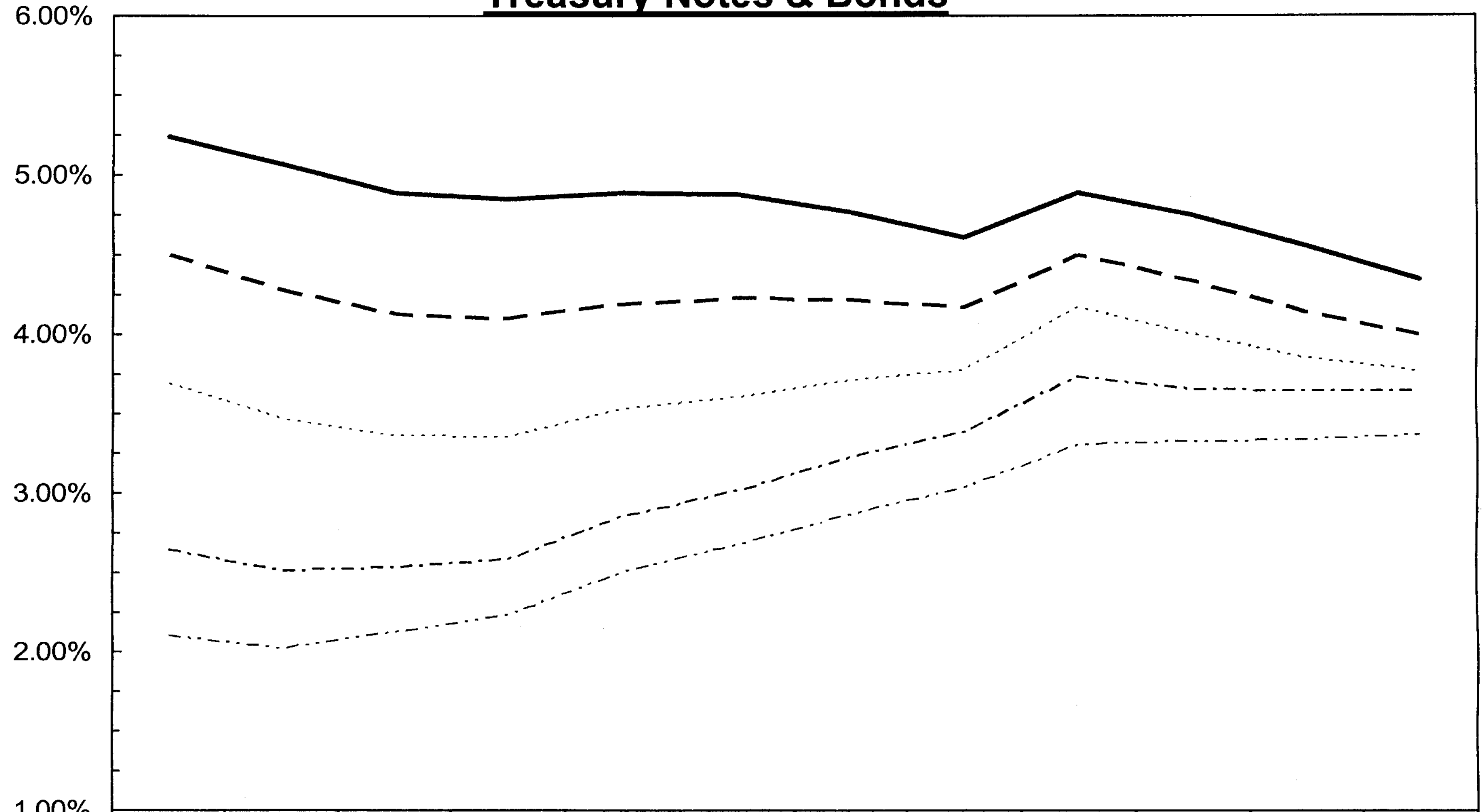
Total Returns	Range: Geometric Mean	Range: Median	Midpoint	Point Estimate: Arithmetic Mean	Average of the Midpoint of Range and Point Estimate
1928-2004					
S&P Public Utility Index	8.55%	11.26%		10.94%	
Public Utility Bonds	5.50%	4.65%		5.79%	
Risk Differential	3.05%	6.61%	4.83%	5.15%	4.99%
1952-2004					
S&P Public Utility Index	10.71%	12.36%		12.29%	
Public Utility Bonds	6.27%	5.22%		6.59%	
Risk Differential	4.44%	7.14%	5.79%	5.70%	5.75%
1974-2004					
S&P Public Utility Index	12.41%	14.82%		14.50%	
Public Utility Bonds	8.89%	9.44%		9.25%	
Risk Differential	3.52%	5.38%	4.45%	5.25%	4.85%
1979-2004					
S&P Public Utility Index	13.01%	14.95%		14.99%	
Public Utility Bonds	9.39%	9.45%		9.74%	
Risk Differential	3.62%	5.50%	4.56%	5.25%	4.91%

**Value Line Betas for
Electric Group**

Company	Beta
Ameren Corp.	0.75
DTE Energy Co.	0.70
Exelon	0.75
FirstEnergy Corp.	0.75
MGE Energy, Inc.	0.60
Vectren Corp.	0.75
WPS Resources	0.75
Wisconsin Energy	0.70
Average	0.72

Source of Information:
Value Line Investment Survey
issues dated April 1, and June 3, 2005

Yields on Treasury Notes & Bonds



	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05
1-Year	2.10%	2.02%	2.12%	2.23%	2.50%	2.67%	2.86%	3.03%	3.30%	3.32%	3.33%	3.36%
2-Year	2.64%	2.51%	2.53%	2.58%	2.85%	3.01%	3.22%	3.38%	3.73%	3.65%	3.64%	3.64%
5-Year	3.69%	3.47%	3.36%	3.35%	3.53%	3.60%	3.71%	3.77%	4.17%	4.00%	3.85%	3.77%
10-Year	4.50%	4.28%	4.13%	4.10%	4.19%	4.23%	4.22%	4.17%	4.50%	4.34%	4.14%	4.00%
20-Year	5.24%	5.07%	4.89%	4.85%	4.89%	4.88%	4.77%	4.61%	4.89%	4.75%	4.56%	4.35%

Yields for Treasury Constant Maturities
Yearly for 2000-2004
and the Twelve Months Ended June 2005

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year
2000	6.11%	6.26%	6.22%	6.16%	6.20%	6.03%	6.23%
2001	3.49%	3.83%	4.09%	4.56%	4.88%	5.02%	5.63%
2002	2.00%	2.64%	3.10%	3.82%	4.30%	4.61%	5.43%
2003	1.24%	1.65%	2.11%	2.97%	3.52%	4.02%	4.96%
2004	1.89%	2.38%	2.78%	3.43%	3.87%	4.27%	5.05%
Five-Year Average	2.95%	3.35%	3.66%	4.19%	4.55%	4.79%	5.46%
Months							
Jul-04	2.10%	2.64%	3.05%	3.69%	4.11%	4.50%	5.24%
Aug-04	2.02%	2.51%	2.88%	3.47%	3.90%	4.28%	5.07%
Sep-04	2.12%	2.53%	2.83%	3.36%	3.75%	4.13%	4.89%
Oct-04	2.23%	2.58%	2.85%	3.35%	3.75%	4.10%	4.85%
Nov-04	2.50%	2.85%	3.09%	3.53%	3.88%	4.19%	4.89%
Dec-04	2.67%	3.01%	3.21%	3.60%	3.93%	4.23%	4.88%
Jan-05	2.86%	3.22%	3.39%	3.71%	3.97%	4.22%	4.77%
Feb-05	3.03%	3.38%	3.54%	3.77%	3.97%	4.17%	4.61%
Mar-05	3.30%	3.73%	3.91%	4.17%	4.33%	4.50%	4.89%
Apr-05	3.32%	3.65%	3.79%	4.00%	4.16%	4.34%	4.75%
May-05	3.33%	3.64%	3.72%	3.85%	3.94%	4.14%	4.56%
Jun-05	3.36%	3.64%	3.69%	3.77%	3.86%	4.00%	4.35%
Twelve-Month Average	2.74%	3.12%	3.33%	3.69%	3.96%	4.23%	4.81%
Six-Month Average	3.20%	3.54%	3.67%	3.88%	4.04%	4.23%	4.66%
Three-Month Average	3.34%	3.64%	3.73%	3.87%	3.99%	4.16%	4.55%

Source: Federal Reserve statistical release H.15

Measures of the Risk-Free Rate

The forecast of Treasury yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated July 1, 2005

Year	Quarter	1-Year Treasury Bill	2-Year Treasury Note	5-Year Treasury Note	10-Year Treasury Note	20-Year Treasury Bond
2005	Third	3.8%	4.0%	4.1%	4.3%	4.7%
2005	Fourth	4.0%	4.2%	4.4%	4.6%	4.9%
2006	First	4.2%	4.4%	4.5%	4.7%	5.1%
2006	Second	4.3%	4.5%	4.7%	4.8%	5.2%
2006	Third	4.4%	4.6%	4.7%	4.9%	5.3%
2006	Fourth	4.5%	4.6%	4.8%	4.9%	5.3%

THE VALUE LINE® Investment Survey®

Part 1 **Summary & Index**

File at the front of the *Ratings & Reports* binder. Last week's *Summary & Index* should be removed.

July 1, 2005

TABLE OF SUMMARY & INDEX CONTENTS

Summary & Index Page Number

SCREENS

The Median of Estimated
PRICE-EARNINGS RATIOS
of all stocks with earnings

18.6

26 Weeks Ago	Market Low 10-9-02	Market High 3-7-05
19.3	14.1	18.9

The Median of Estimated
DIVIDEND YIELDS
(next 12 months) of all dividend paying stocks under review

1.6%

26 Weeks Ago	Market Low 10-9-02	Market High 3-7-05
1.6%	2.4%	1.6%

The Estimated Median Price
APPRECIATION POTENTIAL
of all 1700 stocks in the hypothesized economic environment 3 to 5 years hence

50%

26 Weeks Ago	Market Low 10-9-02	Market High 3-7-05
35%	115%	40%

ANALYSES OF INDUSTRIES IN ALPHABETICAL ORDER WITH PAGE NUMBER

Numeral in parenthesis after the industry is rank for probable performance (next 12 months).

*Reviewed in this week's issue.

In three parts: This is Part 1, the Summary & Index. Part 2 is Selection & Opinion. Part 3 is Ratings & Reports. Volume LX, No. 44.

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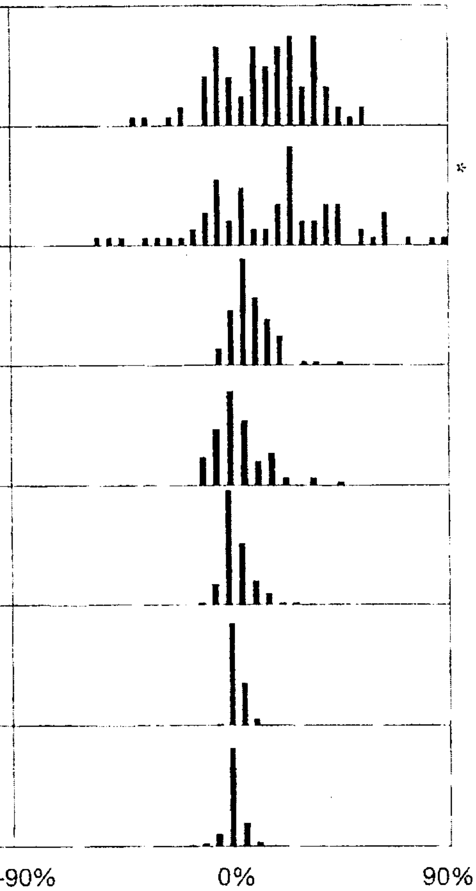
Table 2-1

Basic Series: Summary Statistics of Annual Total Returns

from 1926 to 2004

Series	Geometric Mean	Arithmetic Mean	Standard Deviation	Distribution
Large Company Stocks	10.4%	12.4%	20.3%	
Small Company Stocks	12.7	17.5	33.1	*
Long-Term Corporate Bonds	5.9	6.2	8.6	
Long-Term Government	5.4	5.8	9.3	
Intermediate-Term Government	5.4	5.5	5.7	
U.S. Treasury Bills	3.7	3.8	3.1	
Inflation	3.0	3.1	4.3	



*The 1933 Small Company Stocks Total Return was 142.9 percent.

Comparable Earnings Approach
Using All Value Line Non-Utility Companies with
Timeliness of 3, 4 & 5; Safety Rank of 1, 2 & 3; Financial Strength of B+, B++, A & A+;
Price Stability of 85 to 100; Betas of .60 to .75; and Technical Rank of 3 & 4

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
Alberto Culver	COSMETIC	3	1	A+	100	0.65	3
Ampco-Pittsburgh	STEEL	4	3	B+	90	0.60	3
Archer Daniels Midl'd	FOODPROC	4	3	B+	85	0.70	3
Avon Products	COSMETIC	3	2	B++	90	0.60	3
Banta Corp.	PUBLISH	4	2	B++	95	0.75	3
Brown-Forman 'B'	ALCO-BEV	3	1	A+	100	0.65	3
Capitol Fed. Fin'l	THRIFT	3	2	B++	95	0.75	4
Clorox Co.	HOUSEPRD	3	2	B++	85	0.65	3
ConAgra Foods	FOODPROC	4	1	A	95	0.70	3
Curtiss-Wright	MACHINE	3	2	B++	85	0.70	3
Dean Foods	FOODPROC	3	2	B++	85	0.65	3
Dentsply Int'l	MEDSUPPL	3	2	B++	90	0.70	3
Heinz (H.J.)	FOODPROC	3	1	A+	100	0.60	3
Hillenbrand Inds.	DIVERSIF	5	2	A	90	0.75	3
Hormel Foods	FOODPROC	3	1	A	95	0.70	3
Int'l Flavors & Frag.	CHEMSPEC	3	2	B++	85	0.75	3
Kellogg	FOODPROC	3	2	B++	95	0.60	3
Kraft Foods	FOODPROC	3	1	A+	95	0.65	3
Lancaster Colony	HOUSEPRD	5	1	A+	90	0.75	3
Liberty Corp.	ENTRTAIN	4	2	B+	95	0.75	3
Lockheed Martin	DEFENSE	3	2	A	85	0.70	4
Matthews Int'l	DIVERSIF	3	3	B+	85	0.70	4
McClatchy Co.	NWSPAPER	3	1	A	95	0.75	3
National Presto Ind.	APPLIANC	3	2	B+	100	0.65	3
Northrop Grumman	DEFENSE	3	3	B+	85	0.65	4
Old Nat'l Bancorp	BANKMID	4	2	B++	100	0.70	4
Popular Inc.	BANK	3	3	B+	100	0.75	4
Smucker (J.M.)	FOODPROC	3	2	B++	85	0.65	3
Universal Corp.	TOBACCO	4	2	B++	95	0.70	3
Washington Post	NWSPAPER	4	1	A+	100	0.70	3
Weis Markets	GROCERY	4	1	A	95	0.75	3
Average		3	2		92	0.69	3
Electric Group	Range	3 to 5	1 to 3	B+ to A+	85 to 100	.60 to .75	3 to 4
	Average	4	2	A	96	0.72	3

Source of Information: Value Line Investment Survey for Windows dated June 3, 2004

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 1997-2001 and
Projected 3-5 Year Returns

Company	2000	2001	2002	2003	2004	Average	Projected 2008-10
Alberto Culver	15.3%	15.0%	16.0%	15.3%	14.9%	15.3%	14.0%
Ampco-Pittsburgh	10.0%	NMF	3.4%	1.8%	NMF	5.1%	11.0%
Archer Daniels Midl'd	4.9%	6.1%	6.8%	6.2%	9.7%	6.7%	9.5%
Avon Products	-	-	-	179.0%	89.0%	134.0%	41.0%
Banta Corp.	15.8%	14.2%	13.3%	11.7%	12.6%	13.5%	13.0%
Brown-Forman 'B'	19.6%	17.4%	29.2%	24.5%	23.0%	22.7%	18.0%
Capitol Fed. Fin'l	7.7%	7.4%	9.1%	5.3%	4.8%	6.9%	9.5%
Clorox Co.	23.4%	20.2%	23.8%	42.3%	35.5%	29.0%	54.5%
ConAgra Foods	27.0%	17.1%	18.2%	18.2%	16.4%	19.4%	18.0%
Curtiss-Wright	13.1%	11.6%	10.1%	10.9%	11.3%	11.4%	11.0%
Dean Foods	20.1%	8.5%	17.0%	12.6%	12.2%	14.1%	11.0%
Dentsply Int'l	19.4%	18.0%	17.5%	15.4%	13.6%	16.8%	12.5%
Heinz (H.J.)	65.8%	49.3%	59.5%	41.1%	38.5%	50.8%	22.5%
Hillenbrand Inds.	18.7%	17.7%	19.8%	21.1%	17.5%	19.0%	16.0%
Hormel Foods	19.5%	18.3%	17.0%	14.8%	15.6%	17.0%	15.0%
Int'l Flavors & Frag.	23.7%	25.8%	32.0%	26.9%	23.8%	26.4%	18.5%
Kellogg	72.6%	61.1%	79.4%	54.5%	39.5%	61.4%	25.5%
Kraft Foods	14.2%	8.0%	13.6%	12.1%	10.7%	11.7%	10.0%
Lancaster Colony	24.6%	19.6%	16.6%	16.1%	13.4%	18.1%	14.5%
Liberty Corp.	4.4%	2.8%	6.1%	4.6%	11.0%	5.8%	8.5%
Lockheed Martin	6.0%	10.8%	18.0%	15.6%	18.0%	13.7%	21.0%
Matthews Int'l	22.0%	21.0%	21.1%	17.5%	18.0%	19.9%	15.0%
McClatchy Co.	9.3%	6.3%	12.5%	11.9%	11.1%	10.2%	9.5%
National Presto Ind.	6.2%	2.7%	3.6%	6.3%	6.0%	5.0%	7.0%
Northrop Grumman	15.9%	5.5%	4.8%	4.8%	6.4%	7.5%	11.0%
Old Nat'l Bancorp	14.0%	15.5%	14.8%	9.8%	9.6%	12.7%	15.0%
Popular Inc.	13.8%	13.4%	14.6%	17.1%	15.8%	14.9%	15.5%
Smucker (J.M.)	13.4%	12.2%	9.3%	10.0%	9.0%	10.8%	11.0%
Universal Corp.	23.7%	21.4%	18.1%	18.3%	13.5%	19.0%	12.0%
Washington Post	9.1%	4.3%	11.4%	8.7%	13.7%	9.4%	13.0%
Weis Markets	7.9%	10.1%	10.4%	9.5%	10.0%	9.6%	10.0%
Average						20.6%	15.9%
Median						14.1%	13.0%

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY   CASE NO. 2005-00341

DIRECT TESTIMONY
OF
EVERETT G PHILLIPS

ON BEHALF OF
KENTUCKY POWER COMPANY

September 26, 2005

DIRECT TESTIMONY
OF
EVERETT G. PHILLIPS
ON BEHALF OF
KENTUCKY POWER COMPANY
CASE NO. 2005-00341

Q. Please state your name, business address and position.

A. My name is Everett G. Phillips. My business address is 11233 Kevin Avenue, Ashland, KY 41102. I am the Director of Distribution Operations for the Kentucky Power Company (KPCo).

Q. Please briefly describe your educational background and professional experience.

A. I earned a bachelor's degree in Electrical Engineering in 1985 from West Virginia University. I have 20 years of utility experience with all 20 years focusing on reliability and operations. Prior to my current position, I served as Manager of Distribution Systems in Pikeville, Kentucky, which dealt with day-to-day operations for the line and service crews. Prior to this position, I was the Division Superintendent in Pikeville, Kentucky where I directly managed line mechanics in Hazard and Pikeville areas to provide safe and reliable service to a 100,000 customer base. Prior to that position, I supervised and managed distribution operations at a local area level in Clintwood, Virginia for Appalachian Power Company.

Q. What are your responsibilities as Director of Distribution Operations?

A. I am responsible for overseeing planning, construction, operation and maintenance of KPCo's distribution system. My duties include the reliable delivery of service to our customers and restoring service when outages occur. I also oversee KPCo's distribution and transmission system vegetation management program.

Q. Please describe KPCo's T&D system that serves Kentucky customers.

A. KPCo serves approximately 175,000 retail customers in Kentucky in a service area that covers approximately 5,445 square miles. Our transmission system includes 1,234 miles of transmission lines in Kentucky with voltages ranging up to 765 kV. Our distribution system includes more than 9,546 miles of lower voltage lines. We deliver reliable electric service to our customers by having adequate transmission and distribution facilities in place and by protecting those facilities from hazards that interrupt service.

Q. What is the purpose of your testimony?

A. I will describe KPCo's transmission and distribution (T&D) system and its importance in providing reliable electric service to our customers. My testimony discusses our programs to maintain and enhance the reliability of KPCo's T&D system. More specifically, I will explain how KPCo (1) plans to meet the Commission sponsored "Focused Management Audit" (Audit) recommendations for increased vegetation management; (2) plans to increase its historical O&M expenditure levels to establish a T&D cycle-based vegetation management program, if this Commission approves recovery of the cost of doing so; (3) maintains and improves its service reliability to its customers; and (4) measures reliability on its system.

Q. Are you familiar with the report issued by Schumaker & Company titled "Focused Management Audit" issued on March 24, 2003?

A. Yes, I am familiar with that report, as well as the investigation and Audit activity that lead up to the issuance of the report.

Q. Please explain the background of the Audit report.

A. In 2002, the Kentucky Commission Staff initiated an Audit of KPCo's management and operational efforts regarding maintenance of service quality and service reliability. The Audit was directly associated with KPCo's Hazard service area customers who were experiencing a higher level of service interruptions than other parts of KPCo's service territory. Although the Audit focused on the Hazard service area, it encompassed a review of all KPCo's management and operational efforts to gain a full understanding of how KPCo manages reliability.

The overall Audit assessment points out the difficulty in providing reliable service in mountainous territory and the need to quantify and invest additional financial resources in areas with less than acceptable service reliability.

Q. What are the principal causes of service interruptions that impact reliability?

A. The principal cause of service interruptions on KPCo's system, excluding major events, is contact between a line and a nearby tree or other vegetation. Short momentary interruptions occur when, for example, a tree branch is blown against a line. Longer sustained interruptions can occur when a tree falls through a line and takes it, and perhaps adjacent poles, to the ground.

Tree and animal related outages caused approximately 47.3 percent of the sustained, non-major event outages on KPCo's system in 2004. Animal causes are included in this calculation because tree limbs provide animals a natural path to electrical facilities. The other causes of outages on KPCo's system in 2004 were as follows: equipment failures 23.1 percent; lightning 5.1 percent; prearranged outages 4.0 percent; and all other causes total 20.5 percent.

Q. Please describe KPCo's current T&D Vegetation Management Program.

A. I will describe the Distribution Vegetation Management Program first. KPCo's Distribution "Performance Based" Vegetation Management Program is a comprehensive, integrated vegetation management program designed to ensure that the vegetation along KPCo's distribution circuits is trimmed at the proper time to protect our lines in an environmentally sound and cost-effective manner. KPCo uses a variety of vegetation management practices to control vegetation along its distribution rights-of-way, such as aerial sawing, mechanized trimming, manual trimming (roping, hand climbing), and herbicide applications.

KPCo's vegetation management practices are conducted in accordance with standards established by the American National Standards Institute (ANSI), the Occupational Safety and Health Administration (OSHA), and the National Electrical Safety Code (NESC), and include such things as pruning and removing trees; safety and worker protection; work clearances and training requirements; and safety clearance guidelines.

Each fall, vegetation work plans are developed for the following calendar year. One input into these work plans comes from our visual inspections, which are performed on approximately 50 percent of KPCo's distribution circuits per year as part of our Distribution Asset Programs. Other inputs into the work plan include historical reliability data, line inspections, customer density, customer complaints and time elapsed since vegetation management was last performed. The plan is kept dynamic and flexible to respond to local needs that may arise during the course of the year.

Q. Please describe KPCo's current transmission Vegetation Management Program.

A. KPCo performs aerial patrols of its transmission facilities twice a year, where allowed, and conducts ground-based inspections in those areas where aerial inspections are not allowed. Vegetation management on transmission lines is done on an ongoing basis, depending upon the rate of growth of the vegetation and the voltage of specific transmission lines rather than on a rigid cycle basis (which would schedule circuits for trimming based strictly upon the time elapsed since the last trimming).

The widespread August 14, 2003 Northeast blackout has placed increased scrutiny on vegetation management on transmission lines rights-of-way. As a result, the Federal Energy Regulatory Commission (FERC) is recommending the North America Electric Reliability Council (NERC) develop standards for vegetation management on transmission lines. The present NERC standards apply to transmission circuits operating at 200 kV and above along with critical transmission lines of lower voltage as determined by the applicable Regional Reliability Council. These standards require transmission owners to have a documented vegetation management program, an annual plan, and to report vegetation-related outages.

A revision has been proposed to the existing standards. If adopted, that revision would cause a transmission owner to be deemed noncompliant for tree contacts involving the specified transmission lines. It is anticipated that more vegetation inspections and more vigorous vegetation management on our transmission circuits will be required to comply with such revised standards, thus increasing KPCo's transmission vegetation expenses. Until a revised standard is finalized, however, we cannot estimate the extent of any additional expense.

Q. Mr. Phillips, you have indicated KPCo's largest contributor to outages is trees coming in contact with power lines. Did the Audit agree with your conclusion?

A. Yes. The Audit indicated that tree-caused service interruptions are the largest contributor of unplanned service interruptions. In general the Audit points out tree-caused service interruptions are more of a distribution issue than transmission issue. This is especially true in rural mountainous areas which are physically challenging to access such as KPCo's Hazard service area, where tree exposure on power lines is extremely high, estimated at greater than 90 percent.

Q. Would you please briefly summarize the Audit's vegetation management findings?

A. In general the Audit's findings revealed KPCo's vegetation management approach to manage vegetation on its system demonstrates a high level of professional skill and produces excellent results. In addition, findings concluded the use of industry standard for vegetation management practices, (mechanical clearing, aerial sawing, tree removal, herbicide treatment, etc.) as employed by KPCo, has the potential to minimize both current and future costs.

However, according to the Auditor's conclusions, in spite of good policy, competent staff, and industry best practices, tree-related outages are increasing and a continuation of the current program and its funding levels will not reverse this trend. Additionally, the Audit revealed that KPCo's vegetation management program, comprised of the inventory of trees, tree growth rates, and mortality rates, have not been quantified and are unknown, which prevents KPCo from successfully managing tree-related outages.

It should be noted, the Audit did point out that regardless of any type of vegetation management program employed, reducing tree-caused outages to zero is not feasible because of the fast growing vegetation (e.g., kudzu) KPCo has on its system.

Q. Would you please briefly summarize the Audit's recommendations to improve KPCo's vegetation management program?

A. In general, the Audit recommended two possible ways to minimize tree-caused outages within rights-of-way (ROW). The first recommendation is to establish pruning cycles based on average tree growth. To hold tree-related outages constant, the volume of annual vegetation management work completed must match the annual change in the tree workload inventory. This may require some circuits or portions of circuits to be placed on different cycles that are dictated from actual tree conditions. The Audit's second recommendation to minimize tree-related outages is to substantially increase the use of hot-spotting (trimming where trees are making contact with a conductor) for those trees that pose an immediate threat to service reliability until the system is on a sustainable pruning cycle.

For tree-caused outages outside of ROW, the Audit recommended widening ROW.

Q. Does KPCo agree with these recommendations?

A. KPCo agrees with the Audit's recommendation to use tree growth inventories to better predict the need for future cycle trimming. KPCo does not believe increasing the use of hot-spot trimming provides a comprehensive and cost effective method to manage vegetation on its system. KPCo uses hot-spotting as an essential and appropriate method to control fast growing vegetation that poses an immediate threat to service reliability.

KPCo agrees that widening ROW will further reduce tree caused outages. KPCo attempts to obtain permission from land owners to expand existing ROW, however, in some cases customers are unwilling to permit KPCo to go beyond existing cleared zones.

Q. What is involved in adopting the Audit recommendation to use tree growth inventories to predict future cycle-trimming?

A. To adopt the Audit's recommendation would require additional financial resources to obtain the technology required to inventory vegetation on KPCo's system, to conduct the tree inventory, to increase the number of tree trimming crews, and additional administrative oversight to implement an effective cycle-based program. With these additional resources, KPCo could become more proactive in reducing tree caused outages by inventorying vegetation growth rates, placing circuits or portions of circuits prone to tree caused outages to be trimmed on a cycled basis, and deploying additional tree-trimming crews based on such analysis.

Q. What other elements besides inventorying tree species growth rates would change or become incremental to KPCo's current vegetation management program?

A. KPCo would propose to almost double its 70 tree trimming crews currently employed in KPCo to achieve a cycle-based vegetation approach. KPCo typically employs a range of two to five employees per crew. The additional crews will perform end-to-end tree trimming, tree removals and widening of ROW where possible for all of KPCo's T&D circuits.

Table 1 below represents an estimated summary of the incremental vegetation management work which could be performed if the proposed cycle-based approach were adopted.

Table 1

Actual Right of Way Summary Report			
Test Year	**Trees Trimmed**	**Trees Removed**	**Acres of Brush Cleared**
12 month ending June 2005	47,916	176,649	154,559
Projected Right of Way Summary Report			
Year	**Trees Trimmed**	**Trees Removed**	**Acres of Brush Cleared**
Year 1	166,457	439,189	403,195
Year 2	166,457	439,189	403,195
Year 3	166,457	439,189	403,195

Q. Has KPCo performed any expense projections to fully achieve a cycle based approach in vegetation management?

A. Yes. KPCo has approximately 9,546 overhead distribution line miles and 1,234 miles of transmission lines. The estimates were based on actual line mile tree-trimming clearing expenses, which include base tree trimming work, herbicide application, and incremental tree trimming crews to perform end-to-end clearance, administrative oversight, and follow-up trimming for fast growing vegetation between cycles.

Table 2 provides a total cost summary of KPCo's initial three years of implementing the cycle based program. A three-year period was used to coincide with KPCo's rate case cycle expectation. It will take approximately four years to fully implement a KPCo system-wide cycle based program. The fourth year's costs are expected to be in line with the previous three year cost estimates.

Table 2

KPCo's Estimated Total Vegetation Management O&M and Capital Summary (Millions)						
Year	**Distribution**		**Transmission**		**Total**	
	O&M	Capital	O&M	Capital	O&M	Capital
First	$11.05	$4.97	$1.25	$0.42	$12.30	$5.40
Second	$11.38	$5.12	$1.29	$0.44	$12.67	$5.56
Third	$11.72	$5.27	$1.33	$0.45	$13.05	$5.72

Q. Would you please explain why capital dollars are associated with a vegetation management plan?

A. Capital dollars are used to widen the clear zone of existing rights-of-way.

Q. Has the company identified its T&D vegetation expenses in its test year?

A. Yes. Table 3 below summarizes both T&D vegetation expenses incurred in the twelve-months ending June 2005 test year.

Table 3

KPCo's Vegetation Management Test Year Expenses (Millions)						
Test Year	**Distribution**		**Transmission**		**Total**	
	O&M	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**
12-months ending June 2005	$5.7	$1.79	$.83	N/A	$6.53	$1.79

Q. Would you please provide KPCo's T&D vegetation management's funding levels since 2000?

A. Table 4 below summarizes KPCo's T&D vegetation management's funding levels since 2000.

Table 4

KPCo's Historical Vegetation Management Spend (Millions)						
Year	**Distribution**		**Transmission**		**Total**	
	O&M	Capital	O&M	Capital	O&M	Capital
2000	$2.98	N/A	$.98	N/A	$3.96	N/A
2001	$3.10	N/A	$.92	N/A	$4.02	N/A
2002	$3.63	$.64	$1.12	N/A	$4.75	$.64
2003	$4.41	N/A	$1.03	N/A	$5.44	N/A
2004	$6.11	$1.10	$.87	N/A	$6.98	$1.10

Q. Would you please summarize the incremental difference between KPCo's T&D vegetation management test year costs and the costs of the proposed vegetation management approach being discussed?

A. Yes. Table 5 provides a summary of the incremental difference between Table 2 and Table 3. I provided the incremental T&D O&M expenditures to Witness Wagner for use in this case.

Table 5

KPCo's Estimated Vegetation Management Incremental O&M and Capital Summary (Millions)						
Year	**Distribution**		**Transmission**		**Total**	
	O&M	Capital	O&M	Capital	O&M	Capital
First	$5.33	$3.18	$0.42	$0.42	$5.75	$3.60
Second	$5.66	$3.33	$0.46	$0.44	$6.12	$3.77
Third	$6.00	$3.48	$0.50	$0.45	$6.50	$3.93

Q. How does KPCo maintain and improve reliability on its T&D system?

A. Our programs are designed to maintain and improve reliability by minimizing power interruptions on our T&D system and can be divided into three major categories: T&D Asset Management Programs, Major T&D Reliability Improvements, and T&D Vegetation Management Programs. I have just discussed our vegetation management and would like to address the first two programs.

Q. Please describe the T&D Asset Management Programs.

A. KPCo currently has nine ongoing Distribution Asset Management Programs and three broad categories of Transmission Asset Management Programs, all of which the amount of work in each program will fluctuate per year depending on the system's reliability need. I will first describe the Distribution Asset Management Programs.

The nine Distribution Asset Management Programs and their roles with respect to distribution system reliability are as follows:

<u>Overhead Circuit Facilities Inspection and Maintenance Distribution Programs</u>

Under this Asset Management Program, KPCo visually inspects its overhead facilities to identify and correct potential problems before they happen. This is done on a two-year cycle. To supplement these inspections, KPCo recently began using Electromagnetic Interference (EMI) devices and Spectrum Analyzers, a technology that can help identify problems that are not apparent from a visual inspection. Through these inspections, KPCo can identify and repair such things as broken insulators and blown lightning arresters. As a result of identifying and repairing such problems before they cause an outage, KPCo's customers experience fewer and shorter service interruptions.

Animal Mitigation Program

The objective of this Asset Management Program is to reduce the number of animal-caused outages by installing animal guards on line transformers and other line equipment at locations that have had, or potentially may have, a high risk of animal-caused outages.

Underground Facilities Inspection and Maintenance Program

Under this Asset Management Program, KPCo visually inspects the external, above-ground portions of underground distribution facilities on a two-year cycle to identify and correct problems before they happen. Through these inspections, KPCo identifies and repairs such things as transformers, pedestals, and switchgear.

Pole Inspection And Maintenance Program

The primary objective of this Asset Management Program is to maintain and prolong the mechanical integrity of KPCo's wood poles. Poles in service for 18 years or longer are inspected on an approximate 10-year cycle. As necessary, poles are treated, treated and reinforced, or replaced. This Asset Management Program helps KPCo identify and replace poles that might otherwise fail and cause power interruptions.

Recloser Maintenance / Replacement Program

The objective of this Asset Management Program is to perform preventive maintenance, or to replace, as needed, recloser units that are not operating properly. When recloser devices sense a fault, the device will automatically open and allow a brief period of time for the cause of the fault to clear from the line. The reclosing equipment will then automatically re-energize the circuit. A recloser that does not open and close properly can turn a momentary interruption into a sustained interruption of service which then requires a crew to be dispatched to correct the problem.

Overhead Conductor Program

This Asset Management Program minimizes primary and secondary conductor failures by replacing overhead conductors that show signs of wear. This Asset Management Program targets areas that are experiencing above-average interruptions.

Underground Cable Program

The objective of this Asset Management Program is to correct primary cable deficiencies by restoring the integrity of cable through either cable injection or cable replacement. As is the case with KPCo's Overhead Conductor Program, this Asset Management Program targets areas experiencing above-average interruptions and lessens the likelihood of future interruptions to our customers.

Lightning Mitigation Program

The objective of this Asset Management Program is to reduce the number of lightning-caused outages through the installation of new lightning arresters at locations within areas known to be prone to lightning-caused outages.

Sectionalizing Program

This Asset Management Program improves the reliability of KPCo's distribution circuits by adding new, or modifying existing, sectionalizing devices. Sectionalizing devices allow for smaller circuit segments and fewer customers to be interrupted due to faults that may occur on distribution circuits.

Q. Please describe the transmission aspects of KPCo's T&D Asset Management Programs.

A. Transmission Asset Management Programs fall into the following three broad functional areas: Station Programs, Transmission Line Programs, and Protection & Control (P&C) Programs. The objective of these Transmission Asset Management Programs is to identify potential problems that could cause an interruption of service and implement corrective action to maintain the reliable operation of the transmission equipment.

The three broad functional areas of Transmission Asset Management Programs and their roles with respect to transmission system reliability are as follows:

Station Programs

The station programs include the inspection and maintenance of KPCo's station equipment such as circuit breakers, transformers, switches, reactive devices, station batteries, control buildings, structural steel and associated facilities.

Transmission Line Programs

The transmission line programs provide for the inspection and maintenance of line equipment, which includes the structure, conductor, switches, insulators, hardware and Rights-of-Way. The line inspection programs include walking, climbing, aerial patrol, infrared and emergency inspections. The line maintenance programs address conductor, structural or hardware problems, and include such things as corrosion mitigation for steel structures and groundline treatment for wood poles.

P&C Programs

The P&C programs primarily involve the testing and calibration of protective relays, Supervisory Control and Data Acquisition (SCADA) systems, remote terminal units, power line carrier and pilot wire equipment.

Q. Please describe what is included in the Major T&D Reliability Improvement category.

A. Each year KPCo completes various Major T&D reliability improvements that are not included in the Asset Management Programs category that I described a moment ago. During 2004, for instance, KPCo completed improvements to prevent overloading distribution equipment and improve our ability to restore power to customers. These improvements range from comparatively minor distribution circuit reconfigurations within a residential area to as complex as adding a new substation and associated transmission line to establish new distribution circuits to better serve our customers.

Transmission rehabilitation capital projects are performed to replace equipment that either is no longer economical to maintain or for which spare parts are no longer available.

Q. Mr. Phillips, how does KPCo measure the results of its current programs to provide reliable service to its Kentucky customers?

A. We conduct quarterly customer satisfaction tracking studies for both residential and small commercial customers. These studies are conducted by Market Strategies, Incorporated (MSI). Using this independent survey firm assures the integrity and quality of the data and provides comparative national benchmarking data on standardized questions included in the surveys.

The residential study is administered by telephone using random-digit-dialing within the telephone exchanges located in our service territory. The smaller commercial study also uses a telephone methodology, with sampling of commercial customers with demands of less than 750 kW. Each year about 400 residential and small commercial customers are surveyed.

KPCo's reliability-related customer satisfaction typically scores above the MSI-supplied national benchmark. This is especially true with respect to small commercial accounts. KPCo's small commercial customers indicated high levels of satisfaction in 2004 for overall service reliability (84 percent), outage restoration (86 percent), and power quality (87 percent). These customers were also substantially more satisfied in 2004 than the MSI national average as to outage restoration (+7 points) and power quality (+7 points).

The level of KPCo's 2004 reliability-related residential customer satisfaction, while slightly down from the higher levels of 2001, is still quite high. KPCo's residential customer satisfaction levels, compared to the MSI national average, were at 86 percent for overall service reliability (at the national average), 87 percent for outage restoration (10 points above the average), and 90 percent for power quality (10 points above the average).

Q. Has KPCo received customer complaints related to service reliability in recent years?

A. KPCo has seen an increase in customer complaints concerning reliability issues. However, KPCo believes that the proposed Cycle-Based Vegetation Management approach as well as the asset management programs in place will ensure greater efficiency in customer service and customer satisfaction. Though we have not experienced an unusually large number of complaints considering the size of our system, and while our customer satisfaction rankings have remained high, KPCo recognizes its reliability statistics could be better especially in rural heavily treed mountainous areas which are physically challenging to access. KPCo is committed to maintaining and improving service reliability in Kentucky, which is why I am sponsoring an adjustment to the historical O&M cost levels in this proceeding.

Q. Mr. Phillips, please summarize your testimony.

A. Reliability of service to our customers is important to KPCo. Our customers want and deserve reliable service and we are working diligently to meet that expectation. We have developed new procedures, employed new technology, and are devoting more and more resources to enhance our reliability performance. Implementing the Audit's recommended approach for vegetation management is a critical part of

KPCo's efforts to meet its customers' growing demands for improved reliability for today and into the future. The total cost of implementing this recommended cycle program is significantly above the levels in KPCo's historical expenditures and current test year period. It is important for KPCo and our customers that the Commission approve recovery of the expenditures associated with KPCo's proposal to place its T&D system on a cycle-based vegetation management program to enable us to continue our work to maintain and improve transmission and distribution system reliability.

Q. Does that conclude your direct testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

COMMONWEALTH OF KENTUCKY

CASE NO. 2005-00341

COUNTY OF BOYD

AFFIDAVIT

WITNESS NAME, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Everett G. Phillips
WITNESS NAME

Subscribed and sworn to before me by WITNESS NAME this 20 day of September, 2005.

Notary Public

My Commission Expires March 7, 2007

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY CASE NO. 2005-00341

DIRECT TESTIMONY
OF
DAVID M. ROUSH

ON BEHALF OF
KENTUCKY POWER COMPANY

September 26, 2005

DIRECT TESTIMONY OF
DAVID M. ROUSH, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2005-00341

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DIRECT TESTIMONY OF
DAVID M. ROUSH, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. Please state your name, business address, and position.

A. My name is David M. Roush. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed as a Manager - Regulated Pricing and Analysis for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP). AEP is the parent company of Kentucky Power Company.

Background

Q. Please summarize your educational background and employment history.

A. I graduated from The Ohio State University (OSU) in 1989 with a Bachelor of Science degree in mathematics with a computer and information science minor. In 1999, I earned a Master of Business Administration degree from The University of Dayton. I have completed both the EEI Electric Rate Fundamentals and Advanced Courses. In 2003, I completed the AEP/OSU Strategic Leadership Program.

In 1989, I joined AEPSC as a Rate Assistant. Since that time I have progressed through various positions and was promoted to my current position of Manager – Regulated Pricing and Analysis in July 2003. My responsibilities include the preparation of cost-of-service and rate design analyses for the AEP

System operating companies, and the preparation of special contracts and pricing for customers.

Q. Have you previously submitted testimony in any regulatory proceedings?

A. Yes. I have submitted testimony before the Indiana Utility Regulatory Commission, Michigan Public Service Commission, the Public Service Commission of West Virginia and the Public Utilities Commission of Ohio regarding cost-of-service and rate design related issues.

Q. For whom are you testifying in this proceeding?

A. I am testifying on behalf of Kentucky Power Company, which I will refer to throughout my testimony either as KPCo, or as "the Company".

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support certain test year revenue adjustments, address the allocation of the requested rate increase to the classes, support various changes in the proposed tariffs and the design of the rates for each tariff, and support portions of Section III of this filing with Witness Wagner.

List of Exhibits

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

Exhibit DMR-1 Customer Annualization Adjustment
Exhibit DMR-2 Revenue Allocation

II. ADJUSTMENTS

Customer Migration Adjustment

Q. Are you responsible for the development of the Customer Migration Adjustment?

A. Yes.

Q. Please describe the adjustment.

A. The purpose of the Customer Migration Adjustment is to determine the test year revenue that KPCo would have received if each customer were billed for the entire twelve months of the test year on the tariff under which the customer was taking service at the end of the test year. The adjustment starts with the "per books revenue" as shown in Section III. "Per books revenues" means the revenues from customers as they were actually billed for each month of the test year. During the test year, approximately 900 customers changed tariffs. For example, a customer may have been billed under the MGS tariff for the first seven months of the test year and then billed under the LGS tariff for the remaining five months of the test year. For purposes of the Customer Migration Adjustment, these customers would be re-billed for the entire test year under the tariff as applied at the end of the test year to determine the impact on test year revenues. This restatement of per books revenue was made for each customer who switched tariffs during the test year.

Q. What impact does the Customer Migration Adjustment have on test year revenues?

A. The Customer Migration Adjustment results in an increase of test year revenues of $15,344 as shown in Section V, Workpaper S-4, page 25.

Customer Annualization Adjustment

Q. Are you responsible for the development of the Customer Annualization Adjustment?

A. Yes.

Q. Please explain the purpose of the adjustment.

A. The purpose of the Customer Annualization Adjustment is to restate test year revenues and expenses to reflect, on an annual basis, load growth that occurred during the test year. For example, if the number of residential customers increased during the test year, per books residential kWh sales would have to be increased to reflect the impact of annualizing load growth that occurred within the test year. In addition to the revenue adjustment, test year operating expenses would also have to be increased to reflect the incremental costs associated with annualizing test year load growth.

Q. Please describe the adjustment.

A. The development of the Customer Annualization Adjustment is shown in Exhibit DMR-1. Column (1) of page 1 of Exhibit DMR-1 contains KPCo's current tariffs listed by delivery voltage level. To ensure that the Customer Annualization Adjustment reflects only actual customer growth, the impact of customer migrations has been eliminated by using the data adjusted for the Customer Migration Adjustment. Column (2) contains the total number of customers for the test year, while Column (3) contains the average number of customers for the test year [Column (2) divided by 12]. Column (4) contains the number of customers as of June 30, 2005. Customer growth [Column (5)] is calculated as Column (4) less Column (3).

Customer growth [Column (5)] is then multiplied by test year average kWh per customer [Column (7)] to yield the kWh annualization adjustment [Column (8)]. The kWh annualization adjustment is in turn multiplied by the test year average revenue per kWh [Column (10)] to yield the total revenue annualization adjustment of $195,124 as shown in Column (11).

In addition to the increase in test year revenues, test year operating expenses must also be increased to reflect the incremental cost KPCo would incur in generating 1,679,313 additional kWh. To calculate the incremental operating expenses, an operating ratio approach was used as shown on page 2 of Exhibit DMR-1.

The operating ratio is simply the ratio of operation and maintenance expense, less labor expense, to operating revenues. For KPCo, the operating ratio is 72.85%. Incremental operating expenses are then calculated by multiplying the incremental operating revenue ($195,124) by the operating ratio (72.85%) to yield $142,148. Incremental state and federal income taxes are also deducted to yield a net Customer Annualization Adjustment of $31,956 as shown in Section V, Workpaper S-4, page 24.

III. REVENUE ALLOCATION

Q. Please explain the principles or guidelines that you followed in allocating the proposed revenue increase among the tariff classes.

A. One key objective of ratemaking is to design rates such that they reflect as nearly as possible the actual costs of serving the customer. To fully meet this objective would require that the rates of return for all tariff classes be equalized. The class cost-of-service study prepared by Witness Foust (Exhibit LCF-1) provides the information needed to make this evaluation.

As shown in Column (3) of page 1 of Exhibit DMR-2, the rates of return for the Residential (RS) and the Outdoor Lighting (OL) classes are below the total retail current rate of return of 3.31%. On the other hand, the rates of return for the remaining commercial and industrial classes are considerably above the total retail current rate of return. The Commercial and Industrial Power – Time-of-Day (CIP-TOD) class has a 5.79% rate of return and the Medium General Service (MGS) class has a 9.86% rate of return..

In light of this variation in class rates of return, KPCo proposes to apply the rate increase of $64,796,239 in a manner that provides above average increases to those classes with rates of return below the total retail current rate of return and below average increases to those classes with rates of return in excess of the total retail current rate of return. The actual rate increase for each class was determined by use of an equal percentage subsidy reduction methodology.

Q. Please explain the equal percentage subsidy reduction method of revenue allocation.

A. The first step in the process is to calculate the current subsidy for each class [Column (12) Exhibit DMR-2, page 2]. The current subsidy is defined as the difference between the equalized revenues (revenues if the class rate of return were set equal to the total retail current rate of return of 3.31%) and current class revenues. For example, the current subsidy for the residential class is $24,745,663, which means that residential rates would have to be increased by that amount to raise the class rate of return to 3.31%. Similarly, the current subsidy for the Quantity Power (QP) class is a negative $4,540,902, which means that QP rates would have to be reduced by that amount to lower the class rate of return to 3.31%.

The second step in the process is to calculate the revenues for each class at the total retail proposed rate of return [Column (11) Exhibit DMR-2, page 3]. This shows what each class would pay if all subsidies were eliminated and each class fully paid its actual costs at the proposed revenue level. As can be seen in Column (6), this would produce a significant increase in excess of 44% for the residential class.

The third step in the process is to exercise the principle of gradualism. In this context, it is not reasonable to eliminate all subsidies in this case. However, it is important to make progress toward eliminating interclass subsidies. The amount of such progress should be tempered by a recognition of the rate impacts on the various tariff classes. As such, KPCo proposes to eliminate 10% of the current subsidies from all classes. To accomplish this, 90% of the current subsidy is added back (or deducted, as appropriate) to the class rate increases at proposed equalized rates of return as shown in Columns (12) and (13) of Exhibit DMR-2, page 3.

The final step is simply to recalculate the results using the increase determined in the third step. This is shown in Exhibit DMR-2, page 4.

IV. RATE DESIGN

Q. Please summarize the major rate design modifications proposed by the Company.

A. The significant rate design modifications proposed by the Company are as follows:

TARIFF	MODIFICATION
Small General Service (SGS)	a) Increase availability to customers with average monthly demands less than 10 kW and maximum demands less than 15 kW.
Medium General Service (MGS)	a) Increase size requirement to customers with average monthly demands greater than 10 kW or maximum demands greater than 15 kW.
	b) Increase minimum billing demand to 6 kW from 5 kW.
	c) Add 60% of previous high billing demand during the past 11 months in excess of 100 kW to the minimum billing demand provision.
	d) Eliminate contract capacity requirement for customers less than 500 kW.
MGS Time-of-Day	a) Remove “experimental” designation.
Large General Service (LGS)	a) Revise billing demand to kW instead of kVA.
	b) Eliminate PFCC adjustment to billing energy.

TARIFF	MODIFICATION
Large General Service (LGS)	c) Introduce Excess Reactive Demand Charge per kVA based upon metered data for leading and lagging reactive power.
	d) Eliminate contract capacity requirement for customers less than 500 kW.
	e) Add 60% of previous high billing demand during the past 11 months to the minimum billing demand provision.
	f) Introduce transmission voltage rates.
Quantity Power (QP)	a) Introduce secondary voltage rates.
	b) Introduce metered voltage adjustment provision.
Commercial and Industrial Power – Time-of-Day (CIP-TOD)	a) Introduce metered voltage adjustment provision.
Net Congestion Recovery (NCR)	a) Introduce surcharge to track net congestion cost.

Other tariff changes are discussed by Witness Wagner and identified in Section III of this filing.

Changes in General Service Tariffs SGS and MGS

Q. Please explain the changes to the current SGS and MGS tariffs.

A. The primary change in the SGS and MGS tariffs is the increase in the demand threshold between the two tariffs. Currently, customers must have normal maximum demands less than 5 kW to qualify for the SGS tariff. The Company proposes to change the availability of the SGS tariff to customers with average monthly demands less than 10 kW and maximum monthly demands less than 15 kW. This change will result in nearly 3,200 current MGS customers moving to the SGS tariff.

A corresponding change was made in the availability of the MGS tariff. In addition, the minimum billing demand for the MGS tariff was raised from 5 kW to 6 kW, to recognize that the remaining MGS customers are larger. Lastly, for those grandfathered customers over 100 kW, the minimum billing demand provision now includes a minimum of 60% of the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 kW. This provision allows the Company to modify the size at which contracts are required from 100 kW to 500 kW.

Changes in General Service Tariff LGS

Q. Please explain the changes to the current LGS tariff.

A. As with the MGS tariff, the Company is also modifying the LGS tariff to require contracts for LGS customers over 500 kW, rather than for all LGS customers. The Company is modifying the minimum billing demand provision in a similar manner to the MGS tariff by adding a minimum of 60% of the customer's highest previously established monthly billing demand during the past 11 months.

Lastly, the Company is modifying the provisions of the LGS tariff that address power factor correction. The Company will calculate average monthly power factor based upon leading and lagging reactive energy during the month, as reflected in the proposed LGS billing determinants. This is consistent with the current tariff language. However, instead of billing for all kVA, the Company will only bill for kVA in excess of 115% of the customer's metered demand in kW. The standard demand charge will now be a charge per kW instead of a charge per kVA. In addition, the power factor constant will no longer be applied to metered kWh for billing purposes. These changes will all be accomplished without any change in customer metering. The modified tariff will continue to provide customers with an incentive to correct their power factor while making the tariff billing simpler and easier for customers to understand.

Change in Tariffs QP and CIP-TOD

Q. Please explain the changes to the current QP and CIP-TOD tariffs.

A. The Company proposes to add a Metered Voltage provision to both tariffs. The Metered Voltage provision authorizes the Company to meter customer usage at a voltage different from the delivery voltage and use loss compensating equipment, formulas or multipliers to compensate the measurements to the delivery voltage. This determination is usually made at the time that service is first being established. The Company has had such a provision in its MGS and LGS tariffs for many years and it has worked well for both the Company and customers.

Net Congestion Recovery Tariff

Q. Please explain the Company's proposed Net Congestion Recovery Tariff.

A. As discussed by Witness Bradish, FTR revenues and implicit congestion costs exhibit tremendous volatility and simply should not be included in base rates. The Net Congestion Recovery Tariff would track any deviations in net congestion cost from the annual base amount of negative $3,002,352 that has been included in the test year. The net congestion recovery factor would be set annually each January 1 based upon actual net congestion costs and retail sales in kWh for the most recent twelve month period ending September 30th. Any over- or under-recovery balances that exist as of December 31st of each year would be collected through a balancing adjustment factor in February through December of the subsequent calendar year.

Q. Does this conclude your direct testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

STATE OF OHIO

CASE NO. 2005-00341

COUNTY OF FRANKLIN

AFFIDAVIT

DAVID M. ROUSH, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

David M Roush

DAVID M. ROUSH

Subscribed and sworn to before me by DAVID M. ROUSH this 20th day of September, 2005.

Notary Public

My Commission Expires NOTARY PUBLIC - STATE OF OHIO Attorney At Law
LIFETIME COMMISSION

KENTUCKY POWER COMPANY
DEVELOPMENT OF ANNUALIZATION ADJUSTMENT
TWELVE MONTHS ENDED JUNE 30, 2005

Tariff (1)	Year End Adjusted Number of Customers (2)	June 2005 Annual Average Number of Customers (3)	June 2005 Number of Customers (4)	Customer Growth (5)=(4)-(3)	Year End Adjusted Metered KWH (6)	June 2005 Average KWH Per Customer (7)=(6)/(3)	KWH Annualization Adjustment (8)=(5)x(7)	Year End Migration Revenue (9)	June 2005 Average Revenue Per KWH (10)=(9)/(6)	Revenue Annualization Adjustment * (11)=(8)x(10)
RS Total	1,731,099	144,258.250	144,144	(114.250)	2,339,691,297	16,219	(1,853,021)	$129,944,633	$0.05554	($102,914)
RSLMTOD Total	2,401	200.083	198	(2.083)	5,726,140	28,619	(59,623)	$250,858	$0.04381	($2,612)
SGS Metered Total	202,288	16,857.333	17,118	260.667	66,062,837	3,919	1,021,553	$5,960,030	$0.09022	$92,156
SGS TOD (225)	72	6.000	6	0.000	31,517	5,253	0	$2,889	$0.09166	$0
SGS NM Total	12,121	1,010.083	1,087	76.917	3,247,859	3,215	247,287	$317,463	$0.09775	$24,172
MGS RL (214)	821	68.417	69	0.583	972,745	14,218	8,294	$68,578	$0.07050	$586
MGS Sec Total	135,008	11,250.667	11,265	14.333	587,998,695	52,263	749,103	$38,272,927	$0.06509	$48,765
MGSLMTOD (223)	653	54.417	56	1.583	1,557,314	28,618	45,312	$80,498	$0.05169	$2,342
MGSTOD (229)	903	75.250	75	(0.250)	1,979,194	26,302	(6,576)	$119,371	$0.06031	($397)
MGS Pri Total	999	83.250	87	3.750	19,541,566	234,734	880,253	$1,131,816	$0.05792	$50,984
MGS Sub (236)	264	22.000	20	(2.000)	4,712,277	214,194	(428,388)	$301,805	$0.06405	($27,437)
LGS Sec Total	8,298	691.500	694	2.500	561,099,758	811,424	2,028,560	$29,374,590	$0.05235	$106,201
LGSLMTOD (251)	96	8.000	8	0.000	2,979,155	372,394	0	$146,108	$0.04904	$0
LGS Pri	1,238	103.167	104	0.833	123,742,015	1,199,438	999,532	$6,678,345	$0.05397	$53,949
LGS Sub (248)	722	60.167	60	(0.167)	116,592,376	1,937,823	(322,970)	$5,294,739	$0.04541	($14,668)
QP Pri	372	31.000	29	(2.000)	240,970,735	7,773,250	(15,546,500)	$9,844,164	$0.04085	($635,144)
QP Sub (359)	616	51.333	53	1.667	685,956,073	13,362,781	22,271,302	$27,816,705	$0.04055	$903,072
QP Tran (360)	32	2.667	2	(0.667)	35,434,724	13,288,022	(8,858,681)	$1,459,438	$0.04119	($364,858)
CIP Sub (371)	132	11.000	11	0.000	1,935,314,378	175,937,671	0	$64,892,680	$0.03353	$0
CIP Tran (372)	36	3.000	3	0.000	246,085,254	82,028,418	0	$9,291,975	$0.03776	$0
MW (540)	251	20.917	21	0.083	7,248,584	346,546	28,879	$365,580	$0.05043	$1,457
OL	743,269	61,939.083	62,931	991.917	40,839,034	659	497,321	$4,715,284	$0.11546	$61,686
SL	140,411	11,700.917	11,669	(31.917)	8,237,180	704	(22,324)	$818,090	$0.09932	($2,218)
Total	2,982,102	248,508.500	249,710	1,201.500	7,036,020,707	28,313	1,679,313	$337,148,564		$195,124

* Values may not calculate due to rounding and calculation by lamp instead of customer for lighting.

KENTUCKY POWER COMPANY
DEVELOPMENT OF OPERATING RATIO
TWELVE MONTHS ENDED JUNE 30, 2005

Operating Revenues

Sales of Electricity	$ 336,751,863	Sec. V, Sch.4, P.1, Col.(3), line 1
Net Merger Savings Adjustment	4,018,275	Sec.V, WP S-4, p.9, line 1
State Issues Revenue Adjustment	(2,457,200)	Sec.V, WP S-4, p.10, line 16
Customer Migration Adjustment	15,344	Sec.V, WP S-4, p.25, line 7
Annualized Fuel Adjustment	(1,179,718)	Sec.V, WP S-4, p.27, line 6
Total	$ 337,148,564	

Operating Expenses

Adjusted Operation & Maintenance	$ 266,838,943	Sec. V, Sch.4, P.1 Line 4, Col.(5) - before YEC Adj.
Adjusted Labor Expense	21,231,952	OML Workpaper, plus Sec.V, WP S-4, p.2
Adjusted O&M Less Labor Expense	$ 245,606,991	

Operating Ratio

Operating Ratio	72.85%

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended June 30, 2005

Current Class (1)	Current Revenue (2)	Current ROR % (3)	Current ROR Index (4)	Proposed Increase (5)	Proposed Increase % (6)	Proposed Revenue (7)	Proposed ROR % (8)	Proposed ROR Index (9)
RS	130,089,965	-0.09	(3)	35,508,669	27.30	165,598,634	4.79	61
SGS	6,396,711	7.69	232	977,925	15.29	7,374,636	11.78	150
MGS	40,049,839	9.86	298	5,330,812	13.31	45,380,651	13.74	175
LGS	41,639,263	6.26	189	6,715,919	16.13	48,355,182	10.50	134
QP	39,023,377	6.94	210	5,207,626	13.34	44,231,003	11.11	142
CIP-TOD	74,184,655	5.79	175	9,504,584	12.81	83,689,239	10.08	129
MW	367,037	7.63	231	53,773	14.65	420,810	11.73	150
OL	4,776,969	2.12	64	1,353,543	28.33	6,130,512	6.77	86
SL	815,872	9.77	295	143,388	17.57	959,260	13.65	174
Total	337,343,688	3.31	100	64,796,239	19.21	402,139,927	7.84	100

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended June 30, 2005

Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Current Equalized Rate of Return: Percent Increase (6)	Revenue Increase (7)	Income Increase (8)	Income (9)	ROR % (10)	Sales Revenue (11)	Current Subsidy (12)=(11)-(2)
RS	130,089,965	437,647,617	(374,359)	-0.09	19.02	24,745,663	14,856,502	14,482,143	3.31	154,835,628	24,745,663
SGS	6,396,711	14,341,548	1,102,513	7.69	-16.35	(1,045,924)	(627,939)	474,574	3.31	5,350,787	(1,045,924)
MGS	40,049,839	82,568,918	8,145,054	9.86	-22.51	(9,015,765)	(5,412,776)	2,732,278	3.31	31,034,074	(9,015,765)
LGS	41,639,263	95,181,830	5,962,405	6.26	-11.25	(4,685,052)	(2,812,755)	3,149,650	3.31	36,954,211	(4,685,052)
QP	39,023,377	75,008,460	5,208,308	6.94	-11.64	(4,540,902)	(2,726,212)	2,482,096	3.31	34,482,475	(4,540,902)
CIP-TOD	74,184,655	133,220,660	7,716,724	5.79	-7.43	(5,510,514)	(3,308,336)	4,408,388	3.31	68,674,141	(5,510,514)
MW	367,037	787,445	60,060	7.63	-15.43	(56,637)	(34,003)	26,057	3.31	310,400	(56,637)
OL	4,776,969	17,472,010	369,617	2.12	7.27	347,365	208,547	578,164	3.31	5,124,334	347,365
SL	815,872	2,215,272	216,333	9.77	-29.20	(238,234)	(143,028)	73,305	3.31	577,638	(238,234)
Total	337,343,688	858,443,760	28,406,655	3.31	0.00	0	0	28,406,655	3.31	337,343,688	0

Gross Rev Conversion Factor: 1.665645

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended June 30, 2005

Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Proposed Equalized Rate of Return: Percent Increase (6)	Revenue Increase (7)	Income Increase (8)	Income (9)	ROR % (10)	Sales Revenue (11)	90% of Current Subsidy (12)	Proposed Increase (13)=(7)-(12)
RS	130,089,965	437,647,617	(374,359)	-0.09	44.42	57,779,767	34,689,117	34,314,758	7.84	187,869,732	22,271,098	35,508,669
SGS	6,396,711	14,341,548	1,102,513	7.69	0.57	36,593	21,969	1,124,482	7.84	6,433,304	(941,332)	977,925
MGS	40,049,839	82,568,918	8,145,054	9.86	-6.95	(2,783,377)	(1,671,050)	6,474,004	7.84	37,266,462	(8,114,189)	5,330,812
LGS	41,639,263	95,181,830	5,962,405	6.26	6.00	2,499,372	1,500,543	7,462,948	7.84	44,138,635	(4,216,547)	6,715,919
QP	39,023,377	75,008,460	5,208,308	6.94	2.87	1,120,814	672,901	5,881,209	7.84	40,144,191	(4,086,812)	5,207,626
CIP-TOD	74,184,655	133,220,660	7,716,724	5.79	6.13	4,545,121	2,728,745	10,445,469	7.84	78,729,776	(4,959,463)	9,504,584
MW	367,037	787,445	60,060	7.63	0.76	2,800	1,681	61,741	7.84	369,837	(50,973)	53,773
OL	4,776,969	17,472,010	369,617	2.12	34.88	1,666,172	1,000,316	1,369,933	7.84	6,443,141	312,629	1,353,543
SL	815,872	2,215,272	216,333	9.77	-8.71	(71,023)	(42,640)	173,693	7.84	744,849	(214,411)	143,388
Total	337,343,688	858,443,760	28,406,655	3.31	19.21	64,796,239	38,901,582	67,308,237 67,308,237	7.84	402,139,927	0	64,796,239

Gross Rev Conversion Factor: 1.665645

Exhibit DMR-2

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended June 30, 2005

Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Proposed Revenue Allocation: Percent Increase (6)	Revenue Increase (7)	Income Increase (8)	Income (9)	Proposed Revenue (10)	ROR % (11)
RS	130,089,965	437,647,617	(374,359)	-0.09	27.30	35,508,669	21,318,265	20,943,906	165,598,634	4.79
SGS	6,396,711	14,341,548	1,102,513	7.69	15.29	977,925	587,115	1,689,628	7,374,636	11.78
MGS	40,049,839	82,568,918	8,145,054	9.86	13.31	5,330,812	3,200,448	11,345,502	45,380,651	13.74
LGS	41,639,263	95,181,830	5,962,405	6.26	16.13	6,715,919	4,032,022	9,994,427	48,355,182	10.50
QP	39,023,377	75,008,460	5,208,308	6.94	13.34	5,207,626	3,126,491	8,334,799	44,231,003	11.11
CIP-TOD	74,184,655	133,220,660	7,716,724	5.79	12.81	9,504,584	5,706,247	13,422,971	83,689,239	10.08
MW	367,037	787,445	60,060	7.63	14.65	53,773	32,284	92,344	420,810	11.73
OL	4,776,969	17,472,010	369,617	2.12	28.33	1,353,543	812,624	1,182,241	6,130,512	6.77
SL	815,872	2,215,272	216,333	9.77	17.57	143,388	86,086	302,419	959,260	13.65
Total	337,343,688	858,443,760	28,406,655	3.31	19.21	64,796,239	38,901,582	67,308,237	402,139,927	7.84

Gross Rev Conversion Factor: 1.665645

Exhibit DMR-2

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY

CASE NO. 2005-00341

DIRECT TESTIMONY
OF
ERROL K WAGNER

ON BEHALF OF
KENTUCKY POWER COMPANY

September 26, 2005

DIRECT TESTIMONY OF
ERROL K WAGNER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2005-00341

TABLE OF CONTENTS

DIRECT TESTIMONY OF
ERROL K WAGNER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q: Please state your name, position and business address.

A: My name is Errol K. Wagner. My position is Director of Regulatory Services, Kentucky Power Company ("Kentucky Power, KPCo or Company"). My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40602.

Background

Q: Please summarize your educational background and business experience.

A: I received a Bachelor of Science degree with a major in accounting from Elizabethtown College, Elizabethtown, Pennsylvania in December 1973. I am a Certified Public Accountant. I worked for two certified public accounting firms prior to joining the Pennsylvania Public Utility Commission Staff in 1976. In 1982, I joined the American Electric Power Service Corporation ("AEPSC") as a Rate Case Coordinator. In 1986, I transferred from AEPSC to Kentucky as the Assistant Rates, Tariffs and Special Contracts Director. In July 1987, I assumed my current position.

Q: What are your responsibilities as Director of Regulatory Services?

A: I supervise and direct the Regulatory Services of the Company, which has the responsibility for rate and regulatory matters affecting Kentucky Power. This includes the preparation of and coordination of the Company's exhibits and testimony in rate cases and any other formal filings before state and federal regulatory bodies. Another responsibility is assuring the proper application of the Company's rates in all classifications of business.

Q: To whom do you report?

A: I report to the President of Kentucky Power, Mr. Timothy C. Mosher, who is also located in Frankfort, Kentucky.

Q: Have you previously testified before this Commission?

A: Yes. I have testified before this Commission in numerous regulatory proceedings involving the adjustment in electric base rates, the fuel adjustment clause, the operation of the environmental cost recovery mechanism, approval of certificates of public convenience and necessity and other regulatory matters. I also testified in KPCo's last general adjustment in electric base rates, which was a rate decrease, in Case No. 91-061 which used a test year ending December 31, 1990.

Purpose of Testimony

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony is to support the revenue requirement being proposed by the Company; to support certain known and measurable adjustments to test year capitalization and test year revenues and operating expenses; to support the Kentucky retail jurisdictional factors or amounts; and to support certain tariff changes. In order to fully understand the development of the Company's proposed revenue requirement, which includes certain revenue and expense adjustments, I will give a description of three pertinent Federal Energy Regulatory Commission (FERC) approved agreements of which the Company is a member. These agreements are the AEP Interconnection Agreement, the AEP Transmission Agreement and the AEP Interim Allowance Agreement.

Q: Are you sponsoring any schedules included in the Company's filing or exhibits to your testimony?

A: Yes. I identify the schedules and exhibits that I am sponsoring throughout my testimony.

Q: Were these schedules and exhibits prepared by you or under your direction?

A: Yes.

II. RELEVANT FERC APPROVED AGREEMENTS

The AEP Interconnection Agreement

Q: As background, please briefly describe the AEP Interconnection Agreement and the calculation of the Member Load Ratio (MLR).

A: KPCo, Appalachian Power Company (APCo), Columbus Southern Power Company (CSP), Indiana Michigan Power Company (I&M) and Ohio Power Company (OPCo) are the five AEP System operating companies (hereafter "AEP System – East Zone") which are members of the AEP Pool established pursuant to the Federal Energy Regulatory Commission (FERC) approved AEP Interconnection Agreement. Although each operating company owns specific generating facilities, the AEP System is designed, built and operated on an integrated system basis. The AEP Interconnection Agreement defines the rights and obligations of the five operating companies (each called a "member") and sets out the methodology for allocating the benefits and cost of generation among the members. Significant aspects of the AEP Interconnection Agreement are as follows:

- Requires each member to provide adequate generating facilities (or resources) to meet its firm load requirement.
- Allocates the AEP Pool capacity on the basis of each member's highest non-coincident peak in the preceding twelve months (i.e., Member Load Ratio, or MLR). The MLR is the ratio of a member's highest non-coincident peak in relationship to the total of all members highest non-coincident peak.
- Provides a Capacity Settlement that equalizes responsibility for installed capacity. The capacity settlement equalizes reserve margins by assigning responsibility to each member for its MLR share of system capacity. To the extent that a member's capacity is less than its system responsibility, such deficit company is required to make up its shortfall by paying a capacity charge to the surplus companies, based on the embedded cost of capacity of the surplus companies.
- Each member must make their transmission facilities available to all members for the delivery and receipt of power.

Q: Are there any benefits to the members and their customers as a result of being a party to the AEP Interconnection Agreement?

A: Yes. In fact in the Commission's order in Case No 8271, the Commission found that several benefits accrue to the members as a consequence of the interconnection agreement.

- First, the members benefit from the economies of scale that result from their ability to construct larger size generation and transmission facilities.

The large number of customers and the substantial total load served by the members allows the construction of the larger generation units and higher capacity transmission facilities to be cost justified. Consequently, the unit cost of these facilities is lower than it would have been without the Interconnection Agreement.

- Second, members benefit from enhanced reliability. In addition to a member's own interconnections with other non-affiliated public utilities each member has access to power from all public utilities companies that are interconnected with the other members. This capability is a result of the provision in the Interconnection Agreement that requires each member to make its transmission facilities available for use by all members without charge.
- Third, members have the ability to receive the lowest cost energy available from the other members. This benefit is a result of employing a single dispatching center to dispatch power on an economic basis.
- Fourth, members have access to the services of the Service Corporation. Its expertise encompasses the planning, engineering, design, and construction of power systems. By allocating the cost of the Service Corporation among the AEP System, each member is able to draw upon professional services that would be cost prohibitive and duplicative if provided by each member individually.
- Finally, the fifth benefit is the extensive interconnections between the members and other public utility companies, which enable the members to

have access to a large market for the sale of capacity and energy. Each member benefits from both its right to share in the revenues produced by these sales and the enhanced utilization of its generating capacity.

All of the above benefits continue to be realized today. It should be noted that with the entry into the PJM RTO and PJM Market, both the second and fifth benefits, mentioned above were further enhanced, inasmuch as the AEP System – East Zone resources are now virtually more extensively interconnected and participate within the much larger, centralized PJM market. Company witness Bradish's testimony addresses more specifically the PJM-related issues.

Q: Please describe the calculation of the capacity settlement.

A: Exhibit EKW-1 demonstrates the monthly capacity equalization settlement calculation under the Interconnection Agreement. First, the total members' primary capacity installed is multiplied by each member's MLR to arrive at the member's primary capacity reservation (See Exhibit EKW-1 Columns 1, 2 and 3). This primary capacity reservation is then compared with the installed capacity contributed by each member (See Exhibit EKW-1, Columns 1 and 3). If a member's primary capacity reservation exceeds its installed capacity contribution, the difference is a capacity deficit to be met by the member(s) having the surplus capacity. If a member's installed capacity contribution exceeds its reservation, the difference is a capacity surplus, which is supplied to the AEP System – East Zone by its members. The total capacity surplus in any given month for surplus members always equals the total primary capacity reservation deficiency for the deficit members (i.e., producing a zero surplus/deficit balance for the AEP System – East Zone) (See Exhibit EKW-1, Column 4).

Q: How are the surplus members reimbursed by the deficit members?

A: Exhibit EKW-2 demonstrates the AEP Pool capacity rate calculations under the Interconnection Agreement. The capacity rate is made up of two components: the primary capacity investment rate and the fixed operating rate. The primary capacity investment rate reflects the surplus member's embedded cost of capacity times the carrying charge rate approved by FERC. The fixed operating rate reflects the surplus member's steam plant operations expense and one-half of the steam plant maintenance expense divided by its installed capacity. An example of the capacity rate calculations for the surplus members (I&M and OPCo) is provided in Exhibit EKW-2. Also provided on Exhibit EKW-2 is the weighted average rate, which is paid by the deficit members.

Q: How are the deficit members' capacity settlement charges calculated?

A: A deficit company, such as KPCo, computes its capacity settlement charge by multiplying its capacity deficit by the Pool's weighted average capacity rate of the surplus companies (See Exhibit EKW-1, Columns 5, 6 and 7).

Q: Would you please walk us through the AEP System – East Zone capacity settlement charge calculations for KPCo?

A: Yes. KPCo's monthly MLR is calculated by dividing KPCo's highest non-coincident peak in the preceding twelve months by the total of all of the members' highest non-coincident peaks (1685 MW / 21,498 MW) resulting in an MLR of 0.07838 (See Exhibit EKW-1, Line 2, Column 2). KPCo's primary capacity reservation is determined by multiplying its MLR for the month (0.07838) times the members' total generating capacity (23,173,000 kW). This equals a primary capacity reservation for KPCo of 1,816,300 kW (See Exhibit EKW-1, Line 2, Column 3). KPCo's installed generating capacity is equal to 1,450,000 kW (1,060,000 kW at Big Sandy Generating Plant and 390,000 kW at Rockport Generating Plant). By comparing KPCo's reservation with its installed primary capacity, KPCo has a capacity deficit of 366,300 kW (1,450,000 kW – 1,816,300 kW) for the month (See Exhibit EKW-1, Line 2, Column 4). Multiplying the weighted average capacity rate of the surplus companies (I&M and OPCo) of $8.79/kW times KPCo's capacity deficit of 366,300 kW produces a capacity settlement charge for KPCo of $3,218,782 for the month (See Exhibit EKW-1, Line 8, Column 7).

Q: How soon after the generating facilities are placed in-service do the costs associated with the generating facilities appear in the monthly capacity rate?

A: The Steam Plant Operation Expense and one half of Maintenance Expense will appear in the fixed operating rate for the month in which the expense is incurred by the surplus companies. The primary capacity investment rate reflects the level of Steam Production Plant in-service as of December 31st of the prior year.

Q: What was the annual charge associated with the generating facilities of the surplus companies, incurred by KPCo through the Interconnection Agreement?

A: Based on June 2005, the annual capacity charge incurred by KPCo under the Interconnection Agreement was $28,750,934 (See Section V, Workpaper S-4, Page 30).

AEP Transmission Agreement

Q: As background, please briefly describe the AEP Transmission Agreement.

A: The AEP Transmission Agreement is a FERC approved agreement among the AEP System–East Zone Companies with AEP Service Corporation as agent. A primary reason for the Transmission Agreement is to provide an equitable method of sharing among the members the costs incurred by the members in connection with the ownership of their respective portion of the high voltage transmission system. Also, this agreement enhances the equity among the members for the continued development of a reliable and economic transmission system.

Q: Could you give a brief description of transmission facilities included in the transmission agreement?

A: Yes. For the purposes of this agreement the transmission facilities, commonly referred to as Bulk Power Transmission facilities, include the following:

- All transmission lines operating at a nominal voltage of 138-kV or higher,
- All facilities such as transformers, buses, switchgear and associated facilities located at transmission substations operating at a nominal voltage of 345-kV and above including Extra High Voltage (EHV)/138-kV substations and
- Any other transmission facilities operating at any other voltage that is designated by the Transmission Committee as having been installed for the mutual benefit of all members.

Please keep in mind the Interconnection Agreement's requirement that each member must make their transmission facilities available to all members for the delivery and receipt of power.

Q: What are the obligations of the members under the Transmission Agreement?

A: Each member is required to maintain its respective portion of the Bulk Transmission System, together with all associated facilities and appurtenances, in a suitable condition of repair at all times in order that the System will operate in a reliable and satisfactory manner. Again, much like the Interconnection Agreement, the Transmission Agreement uses the member's MLR and multiplies it times the AEP System–East Zone's total investment in Bulk Transmission facilities investment. That result is compared to the amount of Bulk Transmission investment the member has recorded on its own books and records as of December 31 of the previous year. The difference, should it be a positive (negative) amount determines if the member is a surplus (deficit) member in the Transmission Agreement. Currently, KPCo is a surplus member and receives a payment from the deficit members. During the test year KPCo received $4,322,344 (See Section V, Workpaper S-4, page 37, Column 3) of transmission revenue emanating from the Transmission Agreement. These receipts were recorded as a credit to the member's O&M expense thus reducing the level of cost-of-service the rate payers are required to support in the rate making process.

<u>Interim Allowance Agreement</u>

Q: As background, please briefly describe the AEP Interim Allowance Agreement.

A: KPCo is a member of the FERC approved AEP Interim Allowance Agreement (IAA). In developing the IAA, the AEP System – East Zone companies worked in close cooperation with the AEP Regional Coordinating Committee, a committee consisting of representatives and/or staff from each of the seven state regulatory commissions that oversee the utility operations of the AEP System – East Zone companies. The AEP System - East Zone is designed, built and operated as one electric system, and as such, as a member of the IAA, KPCo shares in the costs and benefits associated with SO_2 emission allowances for the AEP System – East Zone.

The IAA was filed with the FERC in September 1994 and provides for and governs the terms of five basic types of SO_2 allowance transactions among the AEP companies: (1) an annual reallocation of allowances initially allocated by the U.S. Environmental Protection Agency (EPA) to Ohio Power's Gavin Plant; (2) transfer of allowances associated with primary and economy energy transactions among the members; (3) a monthly cash settlement for allowances consumed in connection with power sales to foreign (i.e., non-affiliated) companies; (4) transfers of allowances for current period compliance; and (5) transfers of allowances for future period compliance. Effective September 1996, Modification No. 1 to the IAA made the following changes to the agreement: (1) each member would be required to own its MLR share of the AEP System – East Zone allowance bank at the end of each year; (2) each member would pay for and receive its MLR share of any allowances purchased from third parties, including any allowances purchased at EPA auctions held pursuant to Section 416 of the 1990 Clean Air Act Amendments, 42 U.S.C. §7651o; (3) each member would contribute its MLR share of allowances toward any sale to third parties and would receive its MLR share of the proceeds from any such sales; (4) each member would share in the net proceeds and costs, and accrued carrying charges on such proceeds and costs associated with allowance transactions with non-affiliates which occurred prior to the effective date of Modification No. 1; and (5) each member would retain the proceeds associated with the sale of its withheld allowances at EPA auctions.

III. PROPOSED INCREASE IN ANNUAL REVENUE

Q: Please describe the development of the revenue requirement being proposed by the Company.

A: The Company is proposing an annual revenue requirement of $402,139,927. This represents an increase of $64,796,239 over the Test Year ended June 30, 2005 adjusted revenues of $337,343,688 or an increase of approximately 19.21%. The development of these amounts is shown on Schedule 1 of Section V of the Company's filing. Schedule 2 is a summary schedule supported by various other schedules and workpapers. As shown on Schedule 2, Kentucky Power's adjusted June 30, 2005 Capitalization of $853,082,950 was multiplied by the recommended overall rate of return of 7.89% to determine the Required Net Electric Operating Income of $67,308,245. The Company's test year adjusted Net Electric Operating Income of $28,406,655 was then subtracted from the Required Net Electric Operating Income to determine the required increase of $38,901,590 to the Company's test year Net Electric Operating Income. This amount was multiplied by the Gross Revenue Conversion Factor (GRCF) of 1.6656 to determine the proposed annual increase to retail revenues of $64,796,239.

Q: Why is the GRCF used in determining the required revenue increase?

A: The Required Net Electric Operating Income is an amount which is net of or after uncollectible accounts, State and Federal income taxes. Therefore, in order to calculate the required annual revenue requirement, this is an amount before uncollectible accounts, State and Federal income taxes, one needs to gross up the Net Electric Operating Income for the effects of uncollectible accounts, State and Federal income taxes. The Ohio state income tax is included in the Ohio Franchise tax return.

Q: How was the GRCF of 1.6656 determined?

A: The same methodology was used in calculating the GRCF of 1.6656 as was utilized in the Company's prior cases with one exception. The Ohio and West Virginia state income taxes that KPCo is obligated to pay were incorporated into the GRCF (See Section V, Workpaper S-2, page 2 of 3).

Q: Please explain why KPCo is obligated to pay the Ohio taxes?

A: KPCo, a member of the AEP System – East Zone, along with its ratepayers enjoys the benefits of System Sales being made by AEP. The reason KPCo is obligated to pay state franchise tax in Ohio is because KPCo has a taxable presence in Ohio. AEP System – East Zone's system sales transactions are processed, contracted, and confirmed in Ohio. AEP Service Corporation performs this service as agent for the member affiliates which creates the taxable presence for KPCo. Therefore, KPCo is obligated to pay Ohio state franchise tax on the portion of its apportioned taxable income that relates to the system sales transactions because KPCo receives income from these sales.

Q: Is the Ohio franchise tax planned to be phased-out?

A: Yes. The Ohio franchise tax begins its phase-out with the 2006 return, on which the liability will be 80% of the calculated tax. The liability is reduced by 20% each year until the tax is fully phased-out on the 2010 return, which reflects the 2009 calendar year tax information. As demonstrated on Section V, Workpaper S-2, page 2 of 3, the Company used an average phase-out factor of 24% ((60% + 40% +20%) / 5).

Q: Please explain why KPCo is obligated to pay West Virginia state income tax.

A: KPCo employees who work out of the Williamson, West Virginia Service Building provide electric service to the KPCo retail customers located in the South Williamson, Kentucky service area. The presence of these workers in West Virginia creates a taxable presence with the state, thereby obligating KPCo to pay West Virginia state income tax on its West Virginia apportioned taxable income.

Q: Why do KPCo employees work out of the Williamson, West Virginia Service Building rather than working out of one of KPCo's service buildings located in Kentucky?

A: The Williamson, West Virginia Service Building is less than one mile from South Williamson, Kentucky. The closest KPCo service building is located in Pikeville, Kentucky, which is over 20 miles from South Williamson. The benefit of having KPCo employees working out of the Williamson, West Virginia Service Building is that it reduces travel time to the different job sites, which enables the Company to serve the customers more efficiently and thus improves productivity.

Q: Would you please explain the apportionment factor that is included on Section V, Workpaper S-2, page 2 of 3?

A: Yes. The apportionment factor allocates the portion of KPCo's taxable income, which is taxable in the different taxing jurisdictions. For example, in the Commonwealth of Kentucky 100% of KPCo's taxable net income is taxable in Kentucky and only 7.59% and 0.47% are taxable in the states of Ohio and West Virginia, respectively.

Q: Has the Company reflected the annual effect of Kentucky's new Tax Laws (change in Rate and Consolidation requirement) in this filing?

A: Yes.

Q: Has the Company reflected the annual effect of the Section 199 deduction of the Internal Revenue Code in the calculation of the Federal income tax obligation?

A: Yes. The Company reflected 100% of the annual effect of the Section 199 deduction in the calculation of the State and Federal income tax liability. (See Section V, Workpaper S-10, page 2 of 3, line 89). The net effect is to reduce the Company's State and Federal taxable income by a total of $636,000 annually, thus reducing the Company's tax liability. This approach is consistent with the positions of both the Federal Regulatory Commission's June 2, 2005 guidance letter and the Financial Accounting Standards Board (FASB) Staff Position No. FAS 109-1 titled Application of FASB Statement No. 109, *Accounting for Income Taxes,* which was issued on December 21, 2004.

Q: Since 100% of the effect of Section 199 deduction is reflected in the base rate calculations, would there be any required changes to the Environmental Surcharge monthly calculations?

A: Yes. The monthly Environmental Surcharge calculations should be changed to eliminate the effect of the Section 199 deduction from the Gross Revenue Conversion Factor because 100% of the Section 199 deduction was reflected in calculating the Company's base revenue requirement. The Section 199 deduction should only be reflected once in the ratemaking calculations.

Q: Explain how the weighted average cost of capital of 7.89% was calculated.

A: Please refer to Section V, Workpaper S-2, page 1 of 3. This workpaper demonstrates how the weighted average cost of capital was calculated. The Company first started with the Reapportioned Kentucky Jurisdiction capital as calculated on Section V, Schedule 3 Column 12 for each category of capital. Then the Company calculated the percentage each category of capital is of the Company's total capital by dividing each category's dollar amount by the Company's total dollar amount of capital. This result is shown in Column 4. The annual cost percentage rate (Column 5) was determined as stated in each of the respective footnotes. The cost of long term debt used in the calculation was the Company's actual cost experienced for the test period. The cost of the short term debt used in the calculation was the Company's actual borrowing rate of the AEP money pool as of June 30, 2005. The cost of accounts receivable financing used in the calculation was calculated by using a 13 month average cost experienced by the Company during the test year. The cost of common equity used in the calculation is the same amount recommended by Witness Moul. The Company then took Column 4 times Column 5 for each of the categories of capital to arrive at the weighted average cost of capital for the respective category. The Company then added together each category's weighted average cost of capital to arrive at the Company's total weighted average cost of capital of 7.89%.

Q: Please briefly describe the other schedules included in Section V.

A: Section V consists of 19 schedules and supporting workpapers as required.

Schedule 1 summarizes the components of Net Electric Operating Income for the twelve months ended June 30, 2005, as adjusted, under present rates (Column 3); the effects of the proposed rate increase on those components (Column 4); and, the components of Net Electric Operating Income after giving effect to the proposed rate increase (Column 5). The total amount of rate base and capitalization is also shown as well as the calculated overall rates of return.

Schedule 3 starts with the Company's per book capital balances and adjusts the per book balances to reflect six different adjustments. The net effect of these six adjustments is to increase the per book capitalization by $6,352,279 (Section V, Schedule 3, Columns 10 – 3). These adjustments will be discussed in greater detail later in my testimony.

Schedule 4 shows the total jurisdictional base case summary (Column 3) brought forward from Schedule 5, Column 6; the effects of the rate case adjustments on the various base case components (Column 4); and, the jurisdictional Net Electric Operating Income and rate base summaries as adjusted (Column 5). Details of each rate case adjustment are shown on Section V Workpaper S-4, Pages 1 - 41. The details of the allocations for these adjustments are also shown on the workpapers.

Schedule 5 shows Total Company per books Operating Revenues, Operating Expense, Net Electric Operating Income, and Rate Base (Column 3); the effects of base case eliminations/adjustments are shown in Column 4; Column 5 is the sum of Columns 3 and 4. Column 6 is the Kentucky jurisdictional amounts for the components of Net Electric Operating Income and Total Rate Base. All amounts are referenced to the supporting schedules in Section V.

The remaining schedules of Section V contain either allocations of rate base and/or expenses to the retail jurisdiction, using methods as indicated, or important preliminary determinations needed in the allocation process. The titles of each of these schedules are shown in the Table of Contents of the Company's filing.

IV. COST ALLOCATION TO THE KENTUCKY RETAIL CUSTOMERS

Q: Why is a jurisdictional cost of service necessary?

A: The per book amounts, the modifications, and the adjustments thereto pertain to electric utility operations of the Company for service supplied to all customers, both wholesale and retail. KPCo's retail revenue is approximately 99% of its total revenue; and its wholesale revenue, which includes sales to the cities of Olive Hill and Vanceburg, is approximately 1% of its total revenue. It is, therefore, necessary to separate from these total costs those costs related only to Kentucky jurisdictional retail service. The results of the allocations are then used to determine the jurisdictional cost of service.

Q: Are you responsible for the Kentucky jurisdictional methodology used in the preparation of this case?

A: Yes. The allocation methodology and the allocation factors used to calculate Kentucky retail jurisdictional amounts are shown on the various schedules in the Company's filing. The methodology used in this case is the same methodology used in the Company's last several rate cases.

Q: Where are the allocation factors or allocated amounts shown on the schedules included with this filing?

A: The method of allocation between jurisdictional and non-jurisdictional amounts is generally shown in the right-hand column of each appropriate schedule throughout Section V or on workpapers immediately following each schedule. The results of such allocations are summarized on Schedules 1 through 5 of Section V, which have been previously described.

Q: Are the various schedules of the Company's filing developed in a certain sequence?

A: Yes. In order to develop all the necessary allocation factors the following sequence of development was used:

	TITLE	**SCHEDULE**
1.	Energy Allocation Factors	19
2.	Demand Allocation Factors	18
3.	Electric Plant in Service	11
4.	Accumulated Provision for Depreciation	12
5.	Net Electric Plant in Service	13
6.	Electric Operation & Maintenance Expense	7
7.	Various (No specific sequence)	6, 8, 9, 10, 14, 15, 16, 17
8.	Base Case Summary	5

9.	Adjustments	4
10.	Capitalization	3
11.	Revenue Requirement	2
12.	KY PSC Jurisdiction Summary	1

Q: Would you please describe the determination of the energy allocation factors shown on Schedule 19?

A: Test period sales of energy to the retail customers were determined and adjusted by applying the appropriate transmission and distribution loss factors to obtain KWH adjusted to the generation level. The result was divided by the net total Company energy requirements at the generation level to obtain the retail energy allocation factor.

Q: Please describe the determination of the demand allocation factors shown on Schedule 18.

A: The Company serves retail customers under the jurisdiction of the Kentucky Public Service Commission as well as makes sales to two wholesale customers under the Federal Energy Regulatory Commission (FERC) jurisdiction. One basis for allocating elements of cost of property between these two types of customers is the respective contribution of each of the two classes to the Company's peak demand. The production demand allocation factor reflects the coincident demand of the Company's retail customers at the time of Kentucky Power's monthly peak demand; in other words, the kilowatt contribution of those customers to the Company's monthly peak. The production demand allocation factor was calculated by dividing the average of twelve monthly retail class coincident demands, adjusted for losses to the generation levels by the average of the twelve monthly total Company internal peak demands.

The transmission and sub transmission demand allocation factors are the same as the production demand allocation factor as there are no wholesale loads served at the generation level or from the bulk transmission system.

Q: Please describe the assignment and allocation of Electric Plant in Service.

A: The electric plant values are the functionalized values as of June 30, 2005. These values are allocated as shown on Schedule 11.

Q: What is meant by the functionalized values of Electric Plant in Service as of June 30, 2005?

A: The functionalization of Electric Plant in Service as of June 30, 2005 means to separate the total Electric Plant in Service into the different categories of plant (i.e. production plant, transmission plant, distribution plant, general plant and intangible plant).

Q: Please describe the method of assignment and allocation of Accumulated Provision for Depreciation, Depletion and Amortization.

A: Book amounts have been recorded by functional category. These amounts were allocated in relationship to allocated Electric Plant in Service and appear on Schedule 12.

Q: Please describe the determination of Net Electric Plant.

A: The Net Electric Plant, as shown on Schedule 13, is equal to the difference between corresponding values of allocated Electric Plant in Service and the Accumulated Provision for Depreciation.

Q: How are the Company's total Operation and Maintenance (O&M) expenses adjusted on Schedule 7?

A: The revenues from system sales, which are recorded in the Sales for Resale account and the revenues from various transmission agreements, which are recorded in the Other Electric Revenues account, have been restated for cost of service purposes as a credit to production expense. In addition, non-regulatory Administrative and General (A&G) expenses have been distributed to the other functions in proportion to related payroll expenses.

Q: What does Schedule 6 demonstrate?

A: Schedule 6 allocates the Company's Total Electric Operating Revenues between Kentucky jurisdiction and FERC jurisdiction based on several allocation factors. The Production Plant revenues were allocated on the Energy Allocation Factor. The Transmission Plant revenues were allocated on Gross Plant Transmission Allocation Factor. The Distribution Plant revenues were allocated 100% to the Kentucky retail customers (a Specific Allocation Factor). Also, Schedule 6 calculates the Operating Revenue - Other Allocation Factor and the Operating Revenues Allocation Factor.

Q: How were the adjusted O&M expenses allocated?

A: Schedule 5 of Section V is the base case summary. The Company starts with the Test Year per book numbers in Column 3 and makes various adjustments (Column 4) to determine the electric utility amounts (Column 5). Then, allocation factors referenced in Column 7 are applied to Column 5 amounts to develop the Kentucky Public Service Commission jurisdiction amounts in Column 6.

Q: Please describe the allocation of Depreciation, Depletion and Amortization expense shown on Schedule 8.

A: Depreciation expense applicable to each plant functional group is multiplied by the allocation factor. This develops the Kentucky Public Service Commission jurisdiction amount in Column 4.

Q: Please describe the allocation of Taxes Other Than Federal Income Taxes.

A: Taxes Other Than Federal Income Taxes are shown on Schedule 9. Payroll Related Taxes, except West Virginia Unemployment Insurance, are allocated on the basis of O&M Labor which is shown on Schedule 7. The Federal Environmental Excise and Kentucky Personal Property and Franchise Taxes are allocated on the basis of Gross Plant-Total. The Kentucky PSC Maintenance, the West Virginia Unemployment Insurance, the West Virginia Franchise, and the West Virginia License were allocated to the Kentucky retail customers on a 100% basis because the Company only incurred these taxes because of the Kentucky retail operation.

Q: Please describe the computation of jurisdictional State and Current Federal income taxes.

A: The computation of jurisdictional Current Federal income tax is accomplished by first allocating the various items used in the determination of total company, separate return federal taxable income and applying the statutory federal income tax rate of 35%, as shown on workpapers in Schedule 10. The computation of jurisdictional Deferred Federal income tax is accomplished by applying the appropriate federal income tax rate to the allocated normalized timing differences, as shown on workpapers in Schedule 10, and by amortizing the allocated balances of the embedded Deferred Federal income taxes balances over the appropriate remaining lives. The computation of jurisdictional Deferred Investment Tax Credit is accomplished by amortizing the allocated balances over the appropriate remaining lives. The State income tax is calculated on the basis of operating income before federal income taxes, as shown on Workpaper S-10, page 4.

Q: Were Deferred Taxes and Investment Tax Credits allocated?

A: Yes. Each component was allocated as shown on the workpapers in Schedule 10.

Q: Please describe the allocation of Electric Plant Held for Future Use as it appears in Section V, Schedule 14.

A: The test year-end value of items recorded in the account was allocated using appropriate allocation factors as indicated in Column 6. For example, the Production Plant category was allocated on the Production Demand Allocation Factor, the Transmission Plant category was allocated on the Gross Plant Transmission Allocation Factor and the General Plant category was allocated on Gross Plant Production, Transmission and Distribution Allocation Factor.

Q: Please describe the determination and allocation of the Working Capital Requirement shown on Schedule 15.

A: The first item, Materials and Supplies, is the test year-end value as assigned by functional category and then allocated as shown in Column 6. Prepayments were allocated on the basis of Gross Plant-Total.

The cash working capital component is calculated by using the standard formula of one-eighth of Total Company O&M expenses. This equals one and one half months of the Company's O&M expenses. The allocation basis for the cash working capital component appears in Column 6.

Q: Please describe the allocation of Construction Work in Progress (CWIP) and Allowance for Funds Used During Construction (AFUDC).

A: Each functional component was allocated as shown on Schedule 16. The total utility amount was multiplied by the appropriate allocation factor. The result was the Kentucky Public Service Commission jurisdictional amounts.

Q: Please describe the allocation of Customer Advances for Construction, Customer Deposits and Accumulated Deferred Income Taxes as shown on Schedule 17.

A: The amounts in the Total Electric Utility column for Customer Advances and Customer Deposits are a result of the Kentucky jurisdiction operations. Therefore, 100% of these amounts are allocated to the Kentucky Public Service Commission jurisdiction column. The Accumulated Deferred Federal Income Taxes were allocated on a Gross Plant - Total allocation factor.

V. CAPITALIZATION ADUSTMENTS

Q: Would you please discuss each of the Capitalization adjustments that you are sponsoring?

A: Yes. The details of the Capitalization adjustments are set forth on Section V, Schedule 3, as follows:

Adjustment	Schedule 3
1. Big Sandy Coal Stock Adjustment	Column 4
2. Pension Equity Contribution	Column 5
3. Reliability Capital Adjustment	Column 6

4. FRECO A/C 124 Adjustment — Column 7

5. Carrs Site Adjustment — Column 8

6. Non-Utility Property Adjustment — Column 9

Big Sandy Coal Stock Adjustment
(Schedule 3, Column 4)

KPCo's coal inventory target of days supply to have on hand is 35 days. At June 30, 2005 the Company had 26 days of coal inventory. Therefore, the Company needs to adjust the coal inventory by nine days or 72,854 tons. The average cost of coal in inventory at June 30, 2005 was $49.32 per ton. The coal inventory adjustment required to reflect the Company's 35 day target in inventory is $3,592,837. Since the coal inventory is usually financed with short term debt, the Company increased its June 30, 2005 short term debt by $3,592,837.

Pension Equity Adjustment
(Schedule 3, Column 5)

In accordance with FASB Statement 87, *Employers' Accounting for Pensions,* the Company recorded an additional minimum pension liability, which was recorded as an after-tax equity reduction to Accumulated Other Comprehensive Income (AOCI) of $9,588,250. This negative adjustment to equity represents the current excess of the present value of the Company's pension obligation over the value of its pension fund assets. Statement 87 includes deferrals that smooth the effects of such pension fluctuations that are recognized in pension cost which are included in the cost of service so that pension cost is recognized systematically and gradually. The minimum liability and related AOCI that are recorded on the Company's balance sheet for its underfunded pension plan represent possible future pension expense under FASB Statement 87 and Statement 88 *Employer's Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*, that, if they do not reverse, if interest rates increase, and/or if pension fund investment values increase, will be included in pension expense and cost of service in future periods. For ratemaking purposes it is not appropriate to reduce equity before a cost is actually fixed, known and certain and before it has been included in the cost of providing service. The Company cannot recover this possible future pension cost until it is included in cost of service as an expense. In order to exclude this possible future pension expense, which may never be included in cost of service and recovered, from the determination of current rates, the $9,588,250 AOIC charge to equity was added back to equity capitalization.

Reliability Capital Adjustment
(Schedule 3, Column 6)

As discussed later in testimony and in Witness Phillips testimony, the Company is proposing to increase the test year's level of O&M expense associated with reliability expenditures. In addition, there will also be capital spending associated with the increased level of O&M expense proposed by the Company. On average over a three year period, the Company's capital will be increased by $5,540,000. This amount was spread ratably among the long term debt, short term debt and common equity. Since the Company did not have any short term debt at June 30, 2005, the Company used the accounts receivable financing balance at June 30, 2005 and divided it by the total capitalization at June 30, 2005 and that result, approximately 3.5%, was spread to short term debt.

Franklin Realty Company Account No. 124 Property

(Schedule 3, Column 7)

The Franklin Reality Company (FRECO) investment, recorded in account number 124, was removed from the Company's capitalization ratably among the long term debt, short term debt and common equity. Since the Company did not have any short term debt at June 30, 2005, the Company used the accounts receivable financing balance at June 30, 2005 and divided it by the total capitalization at June 30, 2005 and that result, approximately 3.5%, was spread to short term debt.

Carrs Site Adjustment
(Schedule 3, Column 8)

The Carrs Site investment was removed from the Company's capitalization ratably among the long term debt, short term debt and common equity. Since the Company did not have any short term debt at June 30, 2005, the Company used the accounts receivable financing balance at June 30, 2005 and divided it by the total capitalization at June 30, 2005 and that result, approximately 3.5%, was spread to short term debt.

Non-Utility Property
(Schedule 3, Column 9)

The Non-Utility investment was removed from the Company's capitalization ratably among the long term debt, short term debt and common equity. Since the Company did not have any short term debt at June 30, 2005, the Company used the accounts receivable financing balance at June 30, 2005 and divided it by the total capitalization at June 30, 2005 and that result, approximately 3.5%, was spread to short term debt.

VI. REVENUE AND OPERATING EXPENSE ADJUSTMENTS

Q: Would you please discuss each of the revenue and operating expense adjustments that you are sponsoring?

A: Yes. The details of the revenue and operating expense adjustments set forth on various pages of Section V, Workpaper S-4. Specifically, I am sponsoring the following adjustments:

	Adjustment	**Workpaper S-4 Page No.**
1.	Depreciation Annualization	8
2.	Net Merger Savings Adjustment	9
3.	Elimination of State Issues Revenues	10
4.	Annualization of KPSC Assessment	11
5.	KPSC Mandated Consultants Costs	12
6.	Rate Case Expense Adjustment	13
7.	Storm Damage Normalization	16
8.	Interest on Temporary Investments	18
9.	Miscellaneous Service Charges	21
10.	Annualized CATV Tariff Revenues	22
11.	Net Line of Credit Fee	23
12	Normalization of System Sales	26
13.	Over/(Under) Fuel Revenue	27
14.	Big Sandy Coal Stock	28
15.	Reliability Adjustment	29
16.	AEP Pool Capacity Costs	30
17.	Elimination of FERC Assessment Fees	34

Depreciation Annualization
(Section V, Workpaper S-4, Page 8)

Using the new depreciation rates calculated by Witness Henderson in the depreciation study and multiplying those new rates by the respective functional class of depreciable property investment, the annual depreciation expense is calculated. Comparing the annual depreciation expense calculated using the new depreciation rates versus the annual depreciation expense recorded in the test year, the difference is the required increase adjustment in the amount of $3,654,912.

Net Merger Savings
(Section V, Workpaper S-4, Page 9)

In accordance with the Stipulation and Settlement Agreement dated May 24, 1999 in Case No. 99-149, page 4 and in accordance with Attachment A of that order, the fifth year amount of $7,385,000 is added back as an expense to allow the Net Merger Credit to continue. Also, the actual test year merger credit realized by the retail customers in the amount of $4,018,275 was also added back. The net effect, after considering the tax effect, on Net Electric Operating Income is a negative $2,030,847. These two adjustments fully reflect the effect of the Net Merger Savings.

Elimination of State Issue Settlement Revenue
(Section V, Workpaper S-4, Page 10)

In accordance with the Stipulation and Settlement Agreement dated October 20, 2004, in Case No. 2004-00420, page 5, Section III (1)(d)(i) the parties agreed the additional revenues collected by Kentucky Power from the retail rate adjustment set forth in Section III (1)(a) and Section III (1)(b) of the Stipulation and Settlement Agreement will not be considered by the Kentucky Public Service Commission in establishing Kentucky Power's retail base rates. These additional revenues include a supplemental payment tied to the settlement of state issues and the extension of the Rockport Unit Power Agreement. The Stipulation and Settlement Agreement goes on to say, in any such retail case, Kentucky Power shall be allowed to exclude from the test year period the revenues collected pursuant to Section III (1)(a) and Section III (1)(b). Further, Section III (1)(d)(ii) states that Kentucky Power shall collect the additional revenues as set forth Section III (1)(a) and (1) (b) in addition to such base retail rates established by the Kentucky PSC. The costs associated with the underlying Rockport Units 1 and 2 UPSA are to continue to be included in base rates.

Section (1)(d)(iii) further states that Kentucky Power will develop, and the other Parties will not oppose, a new tariff that provides for the receipt by Kentucky Power of the additional revenues as described in Section III (1)(a) and Section III (1) (b) that will allow the Company to receive the additional revenue amount in addition to its base rates and other charges. Please see Exhibit EKW-13 for the calculations of the new State Issues Settlement rates.

Annualization of KPSC Assessment
(Section V, Workpaper S-4, Page 11)

The Company received an invoice from the Commonwealth of Kentucky on June 16, 2005 in the amount of $535,091 for the Kentucky PSC Assessment fee. During the test year the Company recorded $504,415 in Kentucky PSC assessment fees. The difference in the amount of $30,676 is the Company's proposed adjustment.

KPSC Mandated Consultants' Costs Adjustment
(Section V, Workpaper S-4, Page 12)

KRS 278.255 paragraph (3) states "the Commission shall include the cost of conducting any audits required in this section in the cost of service of the utility for ratemaking purposes". The Company has incurred the cost of three different audits that were performed under this provision of the statute: the 2002 Management Audit, the 2005 Assessment of Kentucky Transmission System and the 2005 Need Assessment of the 161 kV Transmission line. The total cost of these audits is $205,540. Using a three year amortization period results in an annual amount of $68,513. With $19,937 recorded in the test year, this results in an increase adjustment of $48,576.

Rate Case Expense Adjustment
(Section V, Workpaper S-4, Page 13)

The Company's estimated cost of this rate proceeding is $430,700. The Company is proposing to recover this cost over a three-year period. Since there was no rate case costs recorded in the test year, an adjustment of $143,567 is needed to the Company's test year expenses. Expenses included in this amount are costs that would not have been incurred except for the filing of this rate case, such as Outside Legal, Cost of Equity Witness, Demolition Study, Legal Publication Notice and any Employee overtime, Out-of-pocket Employee Expenses and Contract Labor Costs incurred exclusively associated with this rate case filing.

Storm Damage Adjustment
(Section V, Workpaper S-4, Page 16)

The Company adjusted its test year storm damage expense, less straight time labor, by using a three year average storm damage expense, less straight time labor, adjusted by the Handy-Whitman Contract Labor Index. Using the three year average and deducting the test year level of storm damage expense, results in an increase adjustment of $1,524,658.

Temporary Cash Investment Adjustment
(Section V, Workpaper S-4, Page 18)

The temporary cash investment adjustment reflects the actual twelve months ending June 30, 2005 temporary cash investment earnings in the amount of $383,436 into the Company's test year cost of service.

Miscellaneous Service Charges
(Section V, Workpaper S-4, Page 21)

Kentucky Power charges its' customers for Reconnects, Collection Trips, and Bad Checks. As I will discuss later, the Company is proposing to increase the rates charged for such services. This adjustment annualizes test year revenues based upon the proposed new rates.

Annualized CATV Tariff Revenues
(Session V, Workpaper S-4, Page 22)

Kentucky Power charges operators of cable television systems for the attachment of aerial cables, wires and associated appliances to certain distribution system poles. As I will discuss later, the Company is proposing to increase the rates charged for such attachments. This adjustment annualizes test year revenues based on the proposed new rates.

Net Line of Credit Adjustment
(Section V, Workpaper S-4, Page 23)

This adjustment includes in the Company's test year cost of service its actual net line of credit fee incurred for the twelve months ending June 30, 2005 in the amount of $378,305.

System Sales Adjustment
(Section V, Workpaper S-4, Page 26)

The system sales profits that KPCo receives from its membership in the AEP System – East Zone are a significant factor in keeping the Company's rates among the lowest in the Commonwealth as well as the nation. The current operation of the System Sales Clause has also been a driving force that has allowed KPCo to defer requesting an increase in base rates change since 1984. The System Sales Clause reflects the treatment of AEP System – East Zone sales margins allocated to KPCo and allows for the sharing of system sales profits, on a 50/50 basis, of amounts above the value established in base rates, currently $11.3 million. However, if margins are below base rate amounts, both KPCo and the retail customer's share in the short fall on a 50/50 basis. This sharing of system sales is calculated monthly and applied to the customers' bill on a two month lag.

The level of system sales profits received by KPCo from year to year fluctuates widely. The System Sales Clause is designed for the sharing of risks and rewards caused by the changes in the system sales levels. Moreover, the System Sales Clause retains the incentive for the Company, through the AEP Service Corporation, to aggressively market its available power and truly acts as a form of incentive regulation that benefits both customers and shareholders.

During the test year Kentucky Power's share of system sales profits was $26.9M. Of that amount $11.3M was reflected as a credit in the cost of service in which base rates were last calculated and one-half of the balance (i.e., $7.8M) was returned to Kentucky ratepayers through the System Sales Clause Tariff (SSC Tariff). This resulted in an overall benefit of $19.1 million (over 70% of total system sales profit allocated to KPCo) to customers. Also, during the test year only the calendar months November through June's system sales profit level reflected the environmental costs allocated to system sales in the environmental surcharge calculations. This was in accordance with the Commission's order in Case No. 2004-00420 dated December 13, 2004. Therefore, it is appropriate to adjust the monthly level of system sales profit for the calendar months July through October to reflect the environmental costs allocated to the system sales transactions. The Company believes the test year adjusted level of system sales profit of $24.9M is a reasonable level to be built into base rates. This adjustment level includes the full year effect of environmental costs allocated to system sales in the environmental surcharge calculations. Two reasons which support the Company's belief are as follows: (1) the continuing growth in retail load across all of the AEP jurisdictions (i.e. KPCo's internal peak demand was 1,478 MW in 2004 and currently during 2005 the Company's internal peak demand is 1,685 MW or an increase of approximately 14%) results in less generating capability and/or opportunities to make these off system sales, and (2) the rising fuel costs and environmental retrofits to generating facilities either underway or planned also results in less generating capability and/or opportunities to make these off system sales. The test year adjusted level of system sales profits will be a lofty target to achieve.

In order to lessen the monthly variation to the customer, the Company is proposing to use an historical three-year average to develop the monthly base level used on the System Sales Clause Tariff. As an example, for the calendar month of July, the Company took the adjusted level of system sales profit for the month July 2004 and the actual levels of system sales profit for the calendar months July 2003 and July 2002 and added all three amounts together. That result was divided by the total adjusted level of system sales profit for the 36-month period ending June 30, 2005. That approximately 10.70% result was multiplied by the adjusted test year base level of $24.9M, resulting in an adjusted base level of system sales profit for the calendar month of July of $2,658,364. The above calculation was performed for each of the calendar months in the test year to establish the new monthly base level of system sales profit, which is included in the System Sales Clause Tariff.

Over/(Under) Recovery of Fuel
(Section V, Workpaper S-4, Page 27)

As Exhibit EKW- 4 demonstrates, the total test year level of jurisdictional fuel costs was $111,984,770 (Column 9). The total test year level of jurisdictional fuel revenues was $113,164,488 (Column 16) or a difference of $1,179,718 (Column 17). In order to properly design rates so that the appropriate level of revenue is recovered from the Kentucky ratepayers, an adjustment of $1,179,718 to revenues is needed. This adjustment reduces the fuel clause revenues equal to the actual fuel clause expenses. If this adjustment is not made the rates which would be designed would assume that each year these tariffs are in effect the Company would over-recover its fuel costs by $1,179,718. There is an associated deferred tax adjustment in the amount of ($412,901) required with the fuel cost adjustment. The Company has made this adjustment in its prior rate cases and the Commission has accepted this adjustment. In times of rising fuel costs and due to the fact there is a two month lag between when costs are incurred and when costs are recovered in the fuel adjustment clause, an adjustment of this type would be required.

Transmission and Distribution Reliability Adjustment
(Section V, Workpaper S-4, Page 29)

The Company is proposing to increase its test year reliability O&M expenditures on average by $6,123,333 yearly during the next three years. Along with the O&M expense expenditures there is an associated capital expenditure of $3.8M per year. During the next three years the Company will have on average an additional capital investment of $5,540,000. Please refer to the testimony of Witness Phillips for a detailed explanation of the proposed increase to the Company's test year reliability expenses. This adjustment is required to fully comply with the findings of the Commission's Mandated Management Audit.

AEP Pool Capacity Charge Adjustment
(Section V, Workpaper S-4, Page 30)

As I mentioned previously, KPCo is a deficit member of the FERC-approved Interconnection Agreement and KPCo pays a capacity deficit payment to the surplus members every month. Since KPCo full requirement customers' placed a peak demand of 1685 MW (January 24, 2005) on its transmission system, this resulted in KPCo being 7.838% of the AEP System – East Zone's total 21,498 MW peak demands at June 30, 2005. The AEP System – East Zone currently has 23,173

MW of generating capacity. Since KPCo's percentage share is 7.838% of the AEP System – East Zone, under the Interconnection Agreement, KPCo is required to be responsible for 1,816.3 MW (23,173 MW X .07838) of the generating capacity. Because KPCo only has 1,450 MW of generating capacity, KPCo is a deficit member in the AEP Pool by 366.3 MW. KPCo is proposing an adjustment to the charge because there are several events that will take place shortly after the test year that are known and measurable and will affect the level of capacity payments KPCo will pay. These known and measurable events are reflected on Section V, Workpaper S-4, page 30, as follows:

- The effect of the addition of 830 MW of generation capability to Columbus Southern Power's (CSP) generating fleet,
- The effect of the addition of 481 MW of generating capability to Appalachian Power Company's (APCo) generating fleet,
- The net effect of the addition of 289 MW of load to CSP's system,
- The effect of retiring 250 MW of generating capability from AEP's generating fleet and,
- The effect of annualizing known load changes during the test year and shortly thereafter.

The total effect will be to increase KPCo's capacity cost by approximately $9 million. The Company anticipates these adjustments to be concluded by the hearing date in this proceeding.

Elimination of FERC Assessment Charge
(Section V, Workpaper S-4, Page 34)

KPCo joined the PMJ-RTO on October 1, 2004 and KPCo's FERC Assessment payments will be included in the PJM-RTO's costs. Therefore, the amount of FERC Assessment Fees incurred during the test year should be removed from the Company's June 30, 2005 test year cost of service in the amount of $28,063.

Transmission Equalization Revenue Adjustment
(Section V, Workpaper S-4, Page 37)

I previously explained that KPCo is a surplus member under the FERC-approved Transmission Agreement, which shares the cost of ownership and operation of the high voltage transmission system among the members in proportion to each company's MLR. Because the MLRs will be changing due to the known and measurable events happening during and shortly after the test year (See Section V, Workpapaer S-4, page 30), the transmission equalization revenues will also need to be adjusted to reflect these known and measurable changes to KPCo's MLR. The MLR used in this adjustment is consistent with the MLR used in Section V, Workpaper S-4, page 30. The net effect of this adjustment is to increase revenues by $272,404.

Big Sandy Plant Maintenance Adjustment
(Section V, Workpaper S-4, Page 38)

Because KPCo has one generating plant and plant maintenance is performed on a cycle basis, an adjustment to the test year plant maintenance expense is required to reflect a normal level of plant maintenance in the Company's test year cost of service. The Company took the level of steam plant maintenance expense for the twelve months ended June 30, 2003, 2004 and 2005 and adjusted those levels of plant maintenance expense to a constant dollar amount using the Handy-Wittman total steam production plant index. Once the annual constant dollar amounts were calculated, the three year total was divided by three to arrive at an annual normal level of steam plant maintenance expense. That result was compared to the test year level amount, the difference in the amount of $1,298,874, is an increase adjustment proposed by the Company to the Company's test year cost of service.

Pension Prepayment Adjustment
(Section V, Workpaper S-4, Page 40)

In order to address the underfunded status of its qualified pension plan, the Company made quarterly contributions to its pension fund during 2005. These contributions represent cash expenditures in excess of pension cost currently includible in O&M expense and cost of service under the accounting principles governing pension accounting in FASB Statement 87. Including these pension contributions which will be expensed in future periods in rate base will allow the Company to recover its cost of funds for these contributions.

VII. TARIFF ADDITIONS OR CHANGES

Q: Is the Company proposing any permanent additions or changes to the Company's tariffs currently on file with the Commission?

A: Yes. The additions/changes are indicated in the right-hand margin of each tariff sheet attached in Section III. Some of the changes are minor text changes and are self-explanatory. I will address the major changes in my testimony.

The Company is proposing an additional customer payment plan called the Average Monthly Payment (AMP) Plan to be included in its Terms and Conditions of Service Sheet Nos. 2-3 and 2-4 (See Exhibit EKW-5). The Company is also proposing changes to the bill format included in the Company's Terms and

Conditions of Service Sheet Nos. 2-11 through 2-13 (See Exhibit EKW-5). The Company is also proposing to increase the nonrecurring charges listed in its Terms and Conditions of Service Sheet Nos. 2-9 and 2-10 (See Exhibit EKW-5). Additionally, rate changes are being proposed to the Cable Television Pole Attachment Tariff, Sheet Nos. 16-1 through 16-5 (See Exhibit EKW-5).

Average Monthly Payment Plan

Q: What is the Average Monthly Payment Plan?

A: The Average Monthly Payment Plan (AMP Plan) is being proposed by the Company as an alternative payment plan that allows customers to "level out" their monthly payments. Unlike the Equal Payment Plan, the amount paid likely will vary from month to month.

Q: Will the AMP Plan be offered to all customer classes?

A: No. The AMP Plan is designed for the residential and small commercial customers served on the following tariffs: R.S.; R.S.-L.M.-T.O.D.; R.S.-T.O.D.; and S.G.S.

Q: Would you please continue with a general description of the AMP Plan?

A: The AMP Plan is designed to allow the customers to pay an average amount each month, rounded to the nearest dollar, based upon the customer's actual billed amount during the past twelve months. The average payment amount is based upon the current month's total bill plus the preceding eleven months total bills. That result is then divided by the total number of billing days associated with the twelve billings to determine a per day average amount. The calculated daily average amount is multiplied by thirty and rounded to the nearest dollar to determine the current month's payment under the AMP Plan. At the next billing period, the oldest month's billing history is removed, the current month's billing is added and the total is again divided by the total billing days associated with the billings to determine a per day average amount. Again, the daily average amount is multiplied by thirty and again rounded to the nearest dollar to find the new average payment. The average monthly payment is calculated each month in this manner.

Q: How are the differences between the actual billing amounts and the AMP Plan payments addressed?

A: The Company calls these differences the account's deferred balance. Each account's monthly-deferred balance is the difference between the actual charge and the AMP billing amount. These differences are accumulated for twelve months or the AMP Plan year. That accumulated balance is divided by twelve and rounded to the nearest dollar, the result is added or subtracted as appropriate to the calculated AMP Payment for each of the next twelve months or the second AMP Plan Year.

Q: Due to the fact that the deferred billing amount applied to the AMP billing is rounded to the nearest dollar, how is the difference between the deferred billing balance at the end of an AMP Plan year and the amount of the deferred billing amount applied to the following twelve monthly billings addressed?

A: The difference, positive or negative, will be rolled into the accumulated deferred billing balance and used in the calculation of the deferred billing amount applied to the AMP bills during the following twelve months. For example, looking at Exhibit EKW-6, Column 7, line 12 there is a $16.22 accumulated deferred billing balance. That results in a $1.00 rounded amount that is applied to the following twelve months AMP billing amounts (See Column 8, lines 13 and 14). After twelve months only $12.00 of the $16.22 will have been applied to the AMP billing amount. The remaining $4.22 will be included with the following twelve months deferred billings balance and used in calculating the next AMP Plan Year's deferred billing amount which is applied to the AMP bill.

Q: When would settlement of the deferred balance occur?

A: Settlement occurs only when participation in the AMP Plan is terminated. Termination happens if an account is final billed; if the customer requests termination; or if the customer fails to make two or more consecutive monthly payments on an account by the due date. The deferred balance (debit or credit) is then applied to the current billing and must be paid by the due date.

Q: How will the AMP Plan be established in instances where twelve months of billing history is not available?

A: In instances where sufficient billing history is not available, an AMP Plan may be established by using the actual bills rendered throughout the first AMP Plan year. For example, the first month's payment under the AMP Plan will be calculated using the actual month's billing. The second month's payment under the AMP Plan will be calculated using first and second billing amounts. The third month's payment under the AMP Plan will be calculated using first, second and third billing amounts. This will continue until the AMP Plan's anniversary month.

Exhibit EKW-6 demonstrates how the deferred balance and AMP payment would be calculated when sufficient billing history is not available.

Q: Why is the Company proposing the AMP Plan form of payment?

A: The primary motivation behind the Company offering the AMP Plan form of payment is an attempt to address the settlement month concern raised by several customers. In the Equal Payment Plan form of payment the twelfth month is called the settlement month. That being the month when the difference between the total of the eleven equal payments is compared with the total of the twelve months actual billing amounts, that difference is the settlement month amount. The settlement month amount frequently results in the customer owing the Company an amount larger than the equal payment amount, and this creates customer dissatisfaction. AEP has had a plan similar to the AMP Plan form of payment in operation in the west area of our service territory and the customers appear to be more receptive to the AMP Plan versus the Equal Payment Plan.

Q: How does the proposed AMP Plan differ from the already existing Equal Payment Plan?

A: There are two basic differences. First, under the Equal Payment Plan the customer's monthly payment amount remains the same for eleven months and under the AMP Plan the monthly payment amount is the average of the most recent twelve months' billings, and as a result typically will vary from month to month. The second difference is the manner in which the accounts are settled up. Under the Equal Payment Plan the customer's account is settled up during the twelfth month the customer is in the Equal Payment Plan, while under the AMP Plan the settlement amount is divided by twelve and that result is added or subtracted to the average monthly payment amount and recovered or refunded over the next twelve months. As a result, under the AMP Plan the burden (or benefit) of the deferred balance is not borne (or received) in a single month and also under the AMP Plan the differences between the actual billing amounts and the payments amounts should be smaller.

Q: Is the Company proposing to discontinue the Equal Payment Plan?

A. No, not at this time. The Company is proposing the AMP Plan as an alternative payment plan to the Equal Payment Plan. The selection of payment plan (the actual billing amount, Equal Payment Plan or AMP Plan) will continue to be the customer's choice.

Q: Is the new payment plan described in the Company's proposed Terms and Conditions of Service?

A: Yes, the AMP Plan is explained on Sheet Nos. 2-3 and 2-4 under the Payment Section, paragraph B of the Company's proposed Terms and Conditions of Service (See attached Exhibit EKW-5)

Bill Format

Q: Will you please describe the changes to the bill format the Company is proposing in this proceeding?

A: Yes. The Company is proposing several, what I would call cosmetic or minor word changes. We believe these changes will make the bill more customer or reader friendly. The first change is in the top left hand portion of the bill changing the name from American Electric Power to Kentucky Power. The second change is in the top portion of the bill that is returned with the customer's payment. The "Total Amount Due" shaded box has been moved from the middle of the top portion of the bill to the top right hand corner. Also, there has been an "Amount Enclosed" box added immediately below the "Total Amount Due" box. The Winter Care Donation box has been removed from the lower left hand corner of the top portion of the bill that is returned with the customer's payment because of customer lack of participation in this program. Below the proposed "Amount Enclosed" portion of the bill the Company is proposing to change the "Make Checks Payable To:" wording to "Make Checks Payable and Send To".

Q: Are there any other proposed changes to the top portion of the bill that is returned with the customer's payment?

A: Yes. The final proposed change is to the top portion of the bill that is returned with the customer's payment is in the top left hand corner of the bill where customers are to send any customer inquiries. The address has changed from 1701 Central Avenue, P O Box 1428, Ashland, KY 41105-1428 to P O Box 24401, Canton, OH 44701-4401.

Q: Are there any other proposed changes to the bill format?

A: Yes. In the middle portion of the bill in the shaded box the words "Billing Date" are changed to "Bill Date". Also, below the "Previous Charges" portion of the bill the Company is proposing to change the "New Charges" to "Current KPC Charges (1-800-572-1113)". In this same section of the bill the Company is proposing to include the "Net Merger Cr @ 0.0xxxxxx Per KWH", "State Issues Settlement @ 0.0xxxxxx per KWH" and "Environmental Adj. x.xxxxxx %".

Q: Is the Company proposing the same changes on the residential and small commercial bill formats as well as the large power and industrial bill formats?

A: Yes. These changes can be seen on the Company's proposed Terms and Conditions of Service Tariff Sheet Nos. 2-11 through 2-13 (See Exhibit EKW-5).

Special or Nonrecurring Charges

Q: What are Special or Nonrecurring Charges?

A: Special or Nonrecurring charges are charges to customers due to a specific request for certain types of services for which, when the activity is completed, no additional charges will be incurred. Such charges are intended to be limited in nature and to recover the specific cost of the activity.

Q: What are the Special Charges the Company currently has included in its Terms and Conditions of Service?

A: The Company currently has four Special Charges. They are: reconnect for nonpayment; termination or field trip; return check charge and meter test charge.

Q: When were the current Special Charges established?

A: The Company's current Special Charges were established in Case No. 7164. The test year in that case was the twelve months ended March 31, 1978.

Q: Does the Company have different charges within the reconnect for nonpayment category?

A: Yes. The Company has four different categories of reconnect for nonpayment. The four categories are: reconnect for nonpayment during regular hours; reconnect for nonpayment when work continues into overtime at the end of the day and no call out is required; reconnect for nonpayment when call out is required and an employee must be called in to work on an overtime basis to make the reconnection and reconnect for nonpayment when an employee is called out on a Sunday or Holiday when double time is required.

Q: Why does the Company have four different categories of reconnect for nonpayment charges?

A: The Company has four different categories of reconnect for nonpayment charges because each category has its own unique costs associated with the activity. For example, when the Company reconnects a customer after normal business hours, an employee is called out and the Company is obligated to pay that employee time and half for two hours. When the Company reconnects a customer on Sunday or Holiday, an employee is called out and the Company is obligated to pay the employee double time for two hours. The Company incurs different costs depending upon the time of day (or night) the work is performed. Additionally, the intent of the Special Charges is to assign the cost incurred by the Company to perform the specific activity to the customer who required the Company to incur those costs. The customer has the ability to decide what charge they want to pay.

Q: How were the amounts of the different Special Charges determined?

A: The methodology used to determine the Special Charges is the same methodology that was used in Case Nos. 7164 and 91-066. Using data and information supplied by the field employees and their supervisors. The average time to perform the different activities was calculated. The Company then accumulated the total labor costs, transportation costs, fringe benefit costs and any other associated cost incurred to arrive at the total cost to perform each of the different activities (See Exhibit EKW-7).

Q: Would you please walk us through one of the rate calculations on Exhibit EKW-7?

A: Yes. First, the Company used either the average time it takes to perform the activity or, in the activities where call out is required, the amount of time the Company is required to pay the employee to perform the activity (line 1). Second, the Company determined the average transportation time it takes to perform the different activities (line 2). Third, the hourly labor rate for the classification of the employees who perform the different activities (line 3) multiplied by the average time to perform the different activities determined the labor cost (line 6). Fourth, the hourly transportation rate (line 7) was multiplied by the transportation hours (line 2) to arrive at the transportation cost (line 8) to perform the different activities. Fifth, the fringe benefit rate (line 9) was multiplied by the labor cost (line 6) to arrive at the benefit cost (line 10) associated with the different activities. Sixth, with respect to the bad check charge, there is an average bank fee of $4.56 that is charged to the Company by the bank for each bad check the Company deposits. This cost is included in the bad check charge calculations (line 11). Line 12, the total cost line, is the accumulation of the labor cost (line 6) plus the transportation cost (line 8) plus the benefit cost (line 10) and in the case of the bad check charge the bank fees associated with depositing a bad check.

Q: What is the additional annual revenue the Company would anticipate by increasing the Special Charges as described on Exhibit EKW-7, line 13?

A: If the suggested charges (line 13) were in effect for the twelve months ending June 30, 2005 and the number of transactions for each activity remained the same; the total increase in the Company's Special Charges revenue would have been $455,973 (See Exhibit EKW-7, line 17, Column 8).

Q: Did the Company perform the absorption test required by 807 KAR5:011, Section 10 (2) for these changes?

A: Yes. The Company calculated the after tax effect of the $455,973 additional revenues. The result is an increase in net income of $275,073 (See Exhibit EKW-7 line 20 Column 8). Using the June 30, 2005 thirteen-month average common equity of $324,420,513, the earned return on equity would have changed from 6.95% to 7.04% or an increase of .09%.

Q: What was the Company's most recent rate case return on equity authorized by this Commission?

A: The Company's most recent rate case was Case No. 91-066, which had a test year of December 31, 1990. That case was a settled case in which no return on equity was authorized. In the Company's environmental proceeding, Case No. 2002-000169, the Commission authorized a return on equity of 11%. In the Company's most recent environmental proceeding, Case No. 2005-00068 the Commission stated the rate of return authorized in Case No. 2002-000169 would remain the same. Thus, the proposed change to the Company's rate of return on equity will not exceed that authorized rate of return on equity in Case No. 2002-000169.

Q: Was the level of existing Special Charges included in the Company's last general rate case?

A: Yes. The Company proposed to change the amounts charged for these Special Charges in Case No. 91-066. However, in that case a settlement was reached and it was agreed that no changes would be made to the Special Charges.

Q: What is illustrated on Exhibit EKW-8?

A: Exhibit EKW-8 shows the total number of each of the special non-recurring charges per month for the different revenue classes. For example, with respect to the $9.00 reconnect charge there were 4,861 in the residential class of customer.

Q: What is demonstrated on Exhibit EKW-9?

A: Exhibit EKW-9 takes the total number of each of the special non-recurring charges for the twelve months ending June 30, 2005 and spreads the proposed increased revenue among the different customer classes. For example, with respect to the reconnect charge, not requiring any overtime, the Company is proposing a $29.00 increase per transaction, this results in an increase of $148,538 in total reconnect no overtime required revenues. The residential customer class would see an increase of $140,969 of the $148,538 total revenues assuming the same number of transactions during the first year of the new non-recurring charges.

Q: By increasing the non-recurring charges to the Company's actual cost of each transaction, what would be the percent of increase by customer class?

A: Exhibit EKW-9 illustrates the customer class percent of change. For example, by increasing the non-recurring charges to the Company's actual cost of each transaction the residential class of customers would see a 0.3267% increase in revenue. Again this assumes the same number of each transactions in the first year of the new non-recurring charges as were incurred during the twelve months ending June 30, 2005.

Terms and Conditions – Miscellaneous Changes

Q: Are there any other proposed changes to the Company's Terms and Conditions of Service Tariff the Company is requesting?

A: Yes. On Exhibit EKW-5, Sheet No. 2-2, Paragraph 4 (B), "Criteria for Waiver of Deposit Requirement," the Company added a fifth criterion for which the Company may waive a deposit requirement, if the customer voluntarily agrees to sign up for the "Checkless Payment Plan (CPP)". Another proposed change is on Sheet No. 2-7, paragraph 12, Billing Form, the Company changed the Sheet Nos. from 2-9, 2-10, and 2-11 to 2-11, 2-12, and 2-13 to agree with the new pagination.

Residential Tariff

Q: Are there other changes the Company is proposing to its existing tariffs as filed and approved by the Commission at this time?

A: Yes. The Company proposes to revise the Residential Tariff, Special Terms and Conditions Section. The Company proposes to change the line extension from 2,500 feet or less to 1,000 feet or less. This proposed change is consistent with 807 KAR 5:041, Section 11 (1) (See Exhibit EKW-5, Sheet No. 6-3).

Proposed CATV Rate Changes

Q: Is the Company proposing to change the rates charged to Cable Television Pole Attachment (CATV) operators for pole attachments?

A: Yes. The Company utilized the same methodology in calculating the proposed new rates as was used and accepted by this Commission in Case No. 9092. The test year costs were used in the development of the new rates. Exhibit EKW-10 demonstrates how the two- and three-user pole rates were developed. Section V, Workpaper S-4, page 22 demonstrates how the related $143,758 adjustment to the test year revenues was developed.

Q: If the Commission does not accept the Company's requested depreciation rate for Distribution Plant of 3.64%, would this change the rate charged for two-user and three-user attachment rates?

A: Yes, as would a change in the return on common equity which differs from what the Company has requested in this proceeding.

Environmental Surcharge Tariff

Q: Is the Company proposing to roll into base rates the environmental costs reflected in the environmental surcharge calculations?

A: Yes.

Q: Is the Company proposing to eliminate or retire the Environmental Surcharge Tariff?

A: No.

Q: What changes to the Company's Environmental Surcharge tariff is the Company proposing in this proceeding?

A: The Company is proposing to incorporate into its Environmental Surcharge tariff a monthly base level of environmental costs that will be used in calculating the monthly environmental surcharge applied to the customer's monthly bill. The methodology will work very similar to the system sales clause. On Exhibit EKW-5, Sheet No. 29-3, paragraph 6, the Company used the test year's actual monthly level of environmental costs adjusted to reflect the effect of the Commission's September

7, 2005 order in Case No. 2005-00068 as the base level (See Exhibit EKW-11). The Company is also recommending a change to the Environmental Surcharge monthly form ES Form 1.00. The recommendation is to insert two new lines. For illustrative purposes, the Company used the July 2005 ES Form 1.00, which was filed with the Commission and modified it to include the two new lines (please refer to Exhibit EKW-12). Lines 4 and 5 are the two new recommended lines. Line 3 calculates the monthly environmental costs in the same manner as the Company has been calculating the monthly costs. However, now that there is a base level of environmental costs rolled into base rates the Company is proposing the new line 4. When new line 4, the Company's base level of environmental costs built into base rates, is removed from line 3, the Company's monthly environmental cost incurred, the result is an increase/(decrease) of monthly environmental costs line 5, that will flow through the environmental surcharge.

State Issues Settlement

Q: Would you please explain the reasons behind the State Issues Settlement Tariff you are sponsoring in this proceeding?

A: Yes. Pursuant to the terms of the Stipulation and Settlement Agreement and the Commission's December 13, 2004 Order in Case No. 2004-00420, the Company has developed a new tariff to collect the supplemental payments tied to the state issues settlement and the extension of the Rockport purchase power contract, the State Issues Stipulation Tariff, Sheet No. 28-1. Exhibit EKW-13 demonstrates the method used in calculating the State Issues Stipulation Tariff rates. This methodology is the same methodology used when the original State Issues Stipulation rate was calculated and approved in December 2004.

Q: Does this conclude your testimony?

A: Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

COMMONWEALTH OF KENTUCKY

CASE NO. 2005-00341

COUNTY OF FRANKLIN

AFFIDAVIT

Errol K. Wagner, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Errol K Wagner

Errol K. Wagner

Subscribed and sworn to before me by Errol K. Wagner this 23rd day of September 2005.

Judy K Sackett

Notary Public

My Commission Expires January 14, 2009

Exhibit EKW-1

Kentucky Power Company
AEP System Pool
Capacity Equalization Settlement
June 2005 Actual

Calculation of Member Capacity Surplus / (Deficit) (kw)

Ln No.	Company	Member Primary Capacity (kw)	Member Load Ratio	Primary Capacity Reservation (kw)	Capacity Surplus (Deficit) (kw)
		(1)	(2)	(3)=Total kw*(2)	(4)=(1)-(3)
1	APCo	5,899,000	32.933%	7,631,600	(1,732,600)
2	KPCo	1,450,000	7.838%	1,816,300	(366,300)
3	I&M	5,100,000	18.844%	4,366,700	733,300
4	OPCo	8,129,000	23.532%	5,453,100	2,675,900
5	CSP	2,595,000	16.853%	3,905,300	(1,310,300)
6	Total	23,173,000	100.000%	23,173,000	0

Calculation of Member Capacity Settlement ($)

Ln No.	Company	Capacity Surplus (Deficit) (kw)	Capacity Rate ($/kw)	Credit (Charge) ($)
		(5)	(6)	(7)
7	APCo	(1,732,600)	$8.79	($15,224,847)
8	KPCo	(366,300)	$8.79	($3,218,782)
9	I&M	733,300	$12.39	$9,085,587
10	OPCo	2,675,900	$7.80	$20,872,020
11	CSP	(1,310,300)	$8.79	($11,513,978)
12	Total	0		$0

Exhibit EKW-2

Kentucky Power Company
AEP Pool
Capacity Rate Calculations
I & M and OPCo Surplus Members
June 2005 Actual

Ln No.				I&M	OPCo	
		Primary Capacity Investment Rate:				
1		Steam Production Plant as of 12/31/04	($)	$3,489,863,903	$3,289,470,676	
2		Steam Capability as of 12/31/04	(kw)	5,089,000	8,472,000	
3	= (1)/(2)	Average Cost of Investment	($/kw)	$685.77	$388.28	
4		Times Carrying Charge (16.44% / 12 Months)	($/kw/Month)	0.0137	0.0137	
5	= (3)*(4)	Primary Capacity Investment Rate		$9.40	$5.32	
		(Monthly) Fixed Operating Rate:				
6		Steam Plant Operation Expense	($)	$10,194,414	$15,990,840	
7		1/2 Maintenance Expense	($)	$5,023,349	$4,989,048	
8	= (6)+(7)	Subtotal - Fixed Operating Expense	($)	$15,217,763	$20,979,888	
9		Steam Capability	(kw)	5,089,000	8,472,000	
10	= (8)/(9)	Fixed Operating Rate	($/kw)	2.99	2.48	
11	=	**Capacity Rate**	($/kw)	$12.39	$7.80	
		Calculate AEP Pool Average Capacity Rate ($/kw)				
12		Surplus Capacity	(kw)	733,300	2,675,900	
13		Pool's Total Surplus	(kw)	3,409,200	3,409,200	
14		Member's Percent of Pool's Total Surplus	(%)	21.51%	78.49%	
15		Surplus Member's Capacity Rate	($/kw)	$12.39	$7.80	
16		Percentage of Surplus Member's Capacity Rate	($/kw)	2.67	6.12	
17		AEP Pool's Average Capacity Rate	($/kw)			$8.79

Kentucky Power Company
Other Regulatory State Issues Revenues
January 2005 through June 2005

Ln No	Month / Year (1)	Total Company Billed & Accrued kWh (2)	FERC Wholesale Billed & Accrued kWh (3)	Ky Retail Billed & Accrued kWh (4) = (2) - (3)	Ky Retail All Other Billed & Accrued kWh (5)	Rate Per kWh (6)	Ky Retail CIP - TOD Billed & Accrued kWh (7)	Rate Per kWh (8)	Total (9)
1	Jan 05	707,037,043	9,117,707	697,919,336	510,200,392	$0.000440 *	187,718,944	$0.0004613 *	$310,840
2	Feb 05	631,796,567	7,903,100	623,893,467	449,788,619	$0.000847	174,104,848	$0.0005000	$468,023
3	Mar 05	676,007,041	9,391,684	666,615,357	495,031,633	$0.000847	171,583,724	$0.0005000	$505,084
4	Apr 05	523,266,167	6,532,906	516,733,261	330,474,287	$0.000847	186,258,974	$0.0005000	$373,041
5	May 05	536,802,080	6,623,821	530,178,259	342,310,557	$0.000847	187,867,702	$0.0005000	$383,871
6	Jun 05	581,041,256	7,694,039	573,347,217	373,680,056	$0.000847	199,667,161	$0.0005000	$416,341
7	Total	3,655,950,154	47,263,257	3,608,686,897	2,501,485,544		1,107,201,353		$2,457,200

* Rate is Different Due to Proration

Exhibit EKW-3

Kentucky Power Company
Analysis of
Over/(Under) Recovery of Fuel
Test Period Ended 6/30/05

Ln No (1)	month/year (2)	Generation Month KWH Sales (3)	Billed Olive Hill Vanceburg Sales (4)	Juris. KWH Sales (C3-C4) (5)	Total Company Fuel Cost (6)	Juris. Fuel Cost (C5*C10) (7)	Deferred Fuel (8)	Juris. Total Fuel Cost (C7+C8) (9)	Cents/KWH (C6/C3) (10)	Billed and Accrued KWH (11)	Base Fuel (12)	F.A.C. (13)	Base Fuel Revenue (C11*C12) (14)	F.A.C. Revenue (C11*C13) (15)	Total Fuel Revenue (C14+C15) (16)	Over(Under) Recovery of Fuel (C16-C9) (17)
1	May 04	536,409,000		536,409,000	$8,392,239	$8,392,239		$8,392,239	0.01565		0.012					
2	Jun. 04	475,534,000		475,534,000	$7,691,881	$7,691,881		$7,691,881	0.01618		0.012					
3	Jul. 04	524,463,000	8,144,300	516,318,700	$8,324,326	$8,195,059	($655,874)	$7,539,185	0.01587	584,727,430	0.012	0.00365	$7,016,729	$2,134,255	$9,150,984	$1,611,799
4	Aug. 04	582,692,000	7,580,200	575,111,800	$7,676,385	$7,576,523	$1,787,651	$9,364,174	0.01317	573,653,727	0.012	0.00418	$6,883,845	$2,397,873	$9,281,718	($82,456)
5	Sep. 04	527,226,000	7,156,000	520,070,000	$9,056,086	$8,933,168	($940,836)	$7,992,332	0.01718	500,054,901	0.012	0.00387	$6,000,659	$1,935,212	$7,935,871	($56,461)
6	Oct. 04	526,484,000	6,302,300	520,181,700	$9,203,417	$9,093,247	($705,456)	$8,387,791	0.01748	507,000,251	0.012	0.00117	$6,084,003	$593,190	$6,677,193	($1,710,598)
7	Nov. 04	574,415,000	6,989,800	567,425,200	$10,764,814	$10,633,822	$1,465,801	$12,099,623	0.01874	558,490,384	0.012	0.00518	$6,701,885	$2,892,980	$9,594,865	($2,504,758)
8	Dec. 04	680,070,000	9,864,000	670,206,000	$8,790,787	$8,663,282	$832,966	$9,496,248	0.01293	703,407,117	0.012	0.00548	$8,440,885	$3,854,671	$12,295,556	$2,799,308
9	Jan. 05	708,979,000	9,377,800	699,601,200	$11,478,765	$11,326,933	($592,393)	$10,734,540	0.01619	697,919,336	0.012	0.00674	$8,375,032	$4,703,976	$13,079,008	$2,344,468
10	Feb. 05	642,000,000	5,941,500	636,058,500	$9,973,480	$9,881,179	($2,313,448)	$7,567,731	0.01554	623,893,467	0.012	0.00093	$7,486,722	$580,221	$8,066,943	$499,212
11	Mar. 05	700,891,000	11,592,600	689,298,400	$12,584,777	$12,376,627	($345,367)	$12,031,260	0.01796	666,615,357	0.012	0.00419	$7,999,384	$2,793,118	$10,792,502	($1,238,758)
12	Apr. 05	533,848,000	6,486,400	527,361,600	$8,133,712	$8,034,885	$749,550	$8,784,435	0.01524	516,733,261	0.012	0.00354	$6,200,799	$1,829,236	$8,030,035	($754,400)
13	May. 05	550,279,000	6,464,500	543,814,500	$11,093,944	$10,963,616	($1,382,932)	$9,580,684	0.02016	530,178,259	0.012	0.00596	$6,362,139	$3,159,862	$9,522,001	($58,683)
14	June.05	575,651,000	7,789,200	567,861,800	$11,231,213	$11,079,242	($2,672,475)	$8,406,767	0.01951	573,347,217	0.012	0.00324	$6,880,167	$1,857,645	$8,737,812	$331,045
15	July-June Total	7,126,998,000	93,688,600	7,033,309,400	$118,311,706	$116,757,583	($4,772,813)	$111,984,770		7,036,020,707			$84,432,249	$28,732,239	$113,164,488	$1,179,718

Exhibit EKW-4

P.S.C. ELECTRIC NO. 8
CANCELS P.S.C. ELECTRIC NO. 7

Cancels and Supersedes all Previous Schedules

KENTUCKY POWER COMPANY

SCHEDULE OF TARIFFS, TERMS AND CONDITIONS OF SERVICE GOVERNING SALE OF ELECTRICITY

In the Kentucky territory served
By Kentucky Power Company
As stated on Sheet No. 1

Issued by
Errol K. Wagner, Director Regulatory Services
Frankfort, Kentucky

Issued: September 26, 2005 **Effective: October 27, 2005**

INDEX

(Cont'd on Sheet No. 1-2)

KENTUCKY POWER COMPANY

ORIGINAL SHEET NO. 1-2
Canceling ________SHEET NO. 1-2

P.S.C. ELECTRIC NO. 8

INDEX CONT'D

THE ABOVE TARIFFS ARE APPLICABLE TO THE ENTIRE TERRITORY SERVED BY KENTUCKY POWER COMPANY AS ON FILE WITH THE PUBLIC SERVICE COMMISSION AT BOYD, BREATHITT, CARTER, CLAY, ELLIOTT, FLOYD, GREENUP, JOHNSON, KNOTT, LAWRENCE, LESLIE, LETCHER, LEWIS, MAGOFFIN, MARTIN, MORGAN, OWSLEY, PERRY, PIKE AND ROWAN COUNTIES. (T)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E.K. WAGNER (NAME) DIRECTOR OF REGULATORY SERVICES (TITLE) FRANKFORT, KENTUCKY (ADDRESS)

Issued by authority of an Order of the Public Service Commission in Case No. 2005- dated

TERMS AND CONDITIONS OF SERVICE

1. **APPLICATION.**

A copy of the tariffs and standard terms and conditions under which service is to be rendered to the Customer will be furnished upon request at the Company's office and the Customer shall elect upon which tariff applicable to his service his application shall be based.

If the Company requires a written agreement from a Customer before service will be commenced, a copy of the agreement will be furnished to the Customer upon request. (T)

When the Customer desires delivery of energy at more than one point, a separate agreement may be required for each separate point of delivery. Service delivered at each point of delivery will be billed separately under the applicable tariff.

2. **INSPECTION.**

The Customer is responsible for the proper installation and maintenance of the customers' wiring and electrical equipment and the customer shall at all times be responsible for the character and condition thereof. The Company has no obligation to undertake inspection thereof and in no event shall be responsible therefore. However, the Company may refuse to connect to the customer's system if such connection is deemed unsafe by the Company. (T)

Where a Customer's premises are located in a municipality or other governmental subdivision where inspection laws or ordinances are in effect, the Company may withhold furnishing service to new installations until the Company has received evidence that the inspection laws or ordinances have been complied with.

Where a Customer's premises are located outside of an area where inspection service is in effect, the Company may require the delivery by the Customer to the Company of an agreement duly signed by the owner and/or tenant of the premises authorizing the connection to the wiring system of the Customer and assuming responsibility therefore. No responsibility shall attach to the Company because of any waiver of this requirement.

3. **SERVICE CONNECTIONS.**

Service connections will be provided in accordance with 807 KAR 5:041, Section 10.

The Customer should in all cases consult the Company before the Customer's premises are wired to determine the location of Company's point of service connection.

The Company will, when requested to furnish service, designate the location of its service connection. The Customer's wiring must, except for those cases listed below, be brought outside the building wall nearest the Company's service wires so as to be readily accessible thereto. When service is from an overhead system, the Customer's wiring must extend at least 18 inches beyond the building. Where Customers install service entrance facilities which have capacity and layout specified by the Company and/or install and use certain equipment specified by the Company, the Company may supply or offer to own certain facilities on the Customer's side of the point where the service wires attach to the building.

All inside wiring must be grounded in accordance with the requirements of the National Electrical Code or the requirements of any local inspection service authorized by a state or local authority.

When a Customer desires that energy be delivered at a point or in a manner other than that designated by the Company, the Customer shall pay the additional cost of same.

(Cont'd on Sheet No. 2-2)

TERMS AND CONDITIONS OF SERVICE (Cont'd)

4. DEPOSITS.

Prior to providing service or at any time thereafter, the Company may require a cash deposit or other guaranty to secure payment of bills except for customer's qualifying for service reconnection pursuant to 807 KAR 5:006, Section 15, Winter Hardship Reconnection. Service may be refused or discontinued for failure to pay the requested deposit. Upon request from a residential customer the deposit will be returned after 18 months if the customer has established a satisfactory payment record; but commercial deposits will be retained during the entire time that the account remains active. (T

A. Interest

Interest will be paid on all sums held on deposit at the rate indicated in KRS 278.460. The interest will be applied by the Company as a credit to the Customer's bill or will be paid to the Customer on an annual basis. If the deposit is refunded or credited to the Customer's bill prior to the deposit anniversary date, interest will be paid or credited to the Customer's bill on a pro-rated basis.

The Company will not pay interest on deposits after discontinuance of service to the Customer. Retention of any deposit or guaranty by the Company prior to final settlement is not a payment or part payment of any bill for service. The Company shall have a reasonable time in which to obtain a final reading and to ascertain that the obligations of the Customer have been fully performed before being required to return any deposits.

B. Criteria for Waiver of Deposit Requirement

The Company may waive any deposit requirement based upon the following criteria, which shall be considered by the Company cumulatively.

1. Satisfactory payment history.
2. Statement from another utility showing satisfactory payment history.
3. Another customer with satisfactory payment history is willing to sign as a guarantor for an amount equal to the required deposit.
4. Providing evidence of other collateral acceptable to Company, such as Surety Bond.
5. Checkless Payment Plan (CPP) (T)

C. Method of Determination

1. Calculated Deposits

a. Deposit amounts paid by residential customers shall not exceed a calculated amount based upon actual usage data of the Customer at the same or similar premises for the most recent 12-month period, if such information is available. If the actual usage data is not available, the deposit amount shall be based on the average bills of similar customers and premises in the customer class. The deposit shall not exceed 2/12 of the Customer's actual or estimated annual bill. (T)

b. Deposit amounts paid by commercial customers shall not exceed a calculated amount based upon actual usage data of the customer at the same or similar premises for the most recent 12-month period, if such information is available. If the actual usage data is not available, the deposit amount shall be based on the typical bills of similar customers and premises in the customer class. The deposit shall not exceed 2/12 of the customer's actual or estimated annual bill. (T)

(Cont'd on Sheet No. 2-3)

TERMS AND CONDITIONS OF SERVICE (Cont'd)

4. DEPOSITS. (Cont'd.)

D. Additional Deposit Requirement
If a deposit has been waived or returned and the Customer fails to maintain a satisfactory payment record, the Customer may be required to pay a deposit. Factors to be considered when evaluating if a Customer fails to maintain a satisfactory payment record include, but are not limited to; integrity of past payments (returned checks), account credit activity, age of arrearage and frequency of late payments, all during a six month period. The Customer will receive a message on the bill informing the Customer that if the account is not current by the specified date listed on the bill a deposit will be applied to the account the next time the account is billed. If a change in usage or classification of service has occurred, the Customer may be required to pay an additional deposit up to 2/12 of the annual usage.

E. Recalculation of Customers Deposit
When a deposit is held longer than 18 months, the Customer may request that the deposit be recalculated based on the Customer's actual usage. If the amount of deposit on the account differs from the recalculated amount by more than $10.00 for a residential Customer or 10 percent for a non-residential Customer, the Company may collect any underpayment and shall refund any overpayment by check or credit to the Customer's bill. No refund will be made if the Customer's bill is delinquent at the time of the recalculation.

5. PAYMENTS.

Bills will be rendered by the Company to the Customer monthly or in accordance with the tariff selected applicable to the Customer's service.

A. Equal Payment Plan

Residential Customers have the option of paying a fixed amount each month under the Company's Equal Payment Plan. The monthly payment amount will be based on one-twelfth of the Customers estimated annual usage. The payment amount is subject to periodic review and adjustment during the budget year to more accurately reflect actual usage. The normal plan period is 12 months, which may commence in any month.

In the last month of the plan, if the actual usage during the plan period exceeds the amount billed, the Customer will be billed for the balance due. If an overpayment exists, the amount of overpayment will either be refunded to the Customer or credited to the last bill of the period. If a Customer discontinues service with the Company under the Equal Payment Plan, any amounts not yet paid shall become payable immediately.

If a Customer fails to pay bills as rendered under the Equal Payment Plan, the Company reserves the right to revoke the plan, restore the Customer to regular billing, require immediate payment of any deficiency, and require a case deposit or other guaranty to secure payment of bills. (T)

B. Average Monthly Payment Plan (AMP) (N)

The Average Monthly Payment Plan (AMP Plan) is available to the following applicable tariffs; R.S.; R.S.-L.M-T.O.D.; R.S.-T.O.D., and S.G.S. When mutually agreeable the AMP Plan may be offered by the Company to Customers serviced under other tariffs.

The AMP Plan is designed to allow the Customer to pay an average amount each month based upon the actual billed amounts during the past twelve (12) months. The average payment amount is based upon the current month's total bill plus the eleven (11) preceding months. That result is divided by the total billing days associated with the billings to determine a per day average. The daily average amount is multiplied by thirty (30) to determine the current month's payment under the AMP Plan. At the next billing period, the oldest month's billing history is removed, the current month's billing is added and the total is again divided by the total billing days associated with the billings to determine a per day average. Again the daily average amount is multiplied by thirty (30) to find the new average payment amount. The average monthly payment amount is calculated each and every month in this manner. (N)

Cont'd on Sheet No. 2-4)

TERMS AND CONDITIONS OF SERVICE (Cont'd)

B. Average Monthly Payment Plan (AMP) (Cont'd) (N)

The difference between the actual billings and the AMP Plan billings will be carried in a deferred balance. Both the debit and credit differences will accumulate in the deferred balance for the duration of the AMP Plan year, which is twelve consecutive billings months. At the end of the AMP Plan year (anniversary month), the current month's billing plus the eleven (11) preceding month's billing is summed and divided by the total billing days associated with the billings to determine a per day average. That result is multiplied by thirty (30) to calculate the AMP Plan's monthly payment amount. In addition, the net accumulated deferred balance is divided by 12. This result is added or subtracted to the calculated average payment amount starting with the next billing of the new AMP plan year and will be used in the average payment amount calculation for the remaining AMP plan year. Settlement occurs only when participation in the AMP Plan is terminated. This happens if any account is final billed, if the customer requests termination, or at the Company's discretion when the customer fails to make two or more consecutive monthly payments on an account by the due date. The deferred balance (debit or credit) is then applied to the billing now due.

In such instances where sufficient billing history is not available, an AMP Plan may be established by using the actual billing history available throughout the first AMP Plan year. (N)

C. All Payments

All bills are payable at the business offices or authorized collection agencies of the Company within the time limits specified in the tariff. Failure to receive a bill will not entitle a Customer to any discount or to the remission of any charges for non-payment within the time specified. The word "month" as used herein and in the tariffs is hereby defined to be the elapsed time between 2 successive meter readings approximately 30 days apart.

In the event of the stoppage of or the failure of any meter to register the full amount of energy consumed, the Customer will be billed for the period based on an estimated consumption of energy in a similar period of like use.

The tariffs of the Company are net if the account of the Customer is paid within the time limit specified in the tariff applicable to the Customer's service. To discourage delinquency and encourage prompt payment within the specified time limit, certain tariffs contain a delayed payment charge, which may be added in accordance with the tariff under which service is provided. Any one delayed payment charge billed against the Customer for non-payment of bill or any one forfeited discount applied against the Customer for non-payment of bill may be remitted, provided the Customer's previous accounts are paid in full and provided no delayed payment charge or forfeited discount has been remitted under this clause during the preceding 6 months.

6. UNDERGROUND SERVICE.

When a real estate developer desires an underground distribution system within the property which he is developing or when a Customer desires an underground service, the real estate developer or the Customer, as the case may be, shall pay the Company the difference between the anticipated cost of the underground facilities so requested and the cost of the overhead facilities which would ordinarily be installed in accordance with 807 KAR 5:041, Section 21, and the Company's underground service plan as filed with the Public Service Commission. Upon receipt of payment, the Company will install the underground facilities and will own, operate and maintain the same.

7. COMPANY'S LIABILITY.

The Company will use reasonable diligence in furnishing a regular and uninterrupted supply of energy, but does not guarantee uninterrupted service. The Company shall not be liable for damages in case such supply should be interrupted or fail by reason of an event of Force Majeure. Force Majeure consists of an event or circumstance which prevents Company from providing service, which event or circumstance was not anticipated, which is not in the reasonable control of, or the result of negligence of, the Company, and which, by the exercise of due diligence, Company is unable to overcome or avoid or causes to be avoided. Force Majeure events includes act of God, the public enemy, accidents, labor disputes, orders or acts of civil or military authority, breakdowns or injury to the machinery, transmission lines, distribution lines or other facilities of the Company, or extraordinary repairs. (T)

(Cont'd on Sheet 2-5)

TERMS AND CONDITIONS OF SERVICE (Cont'd)

7. **COMPANY'S LIABILITY (Cont'd)**

Unless otherwise provided in a contract between Company and Customer, the point at which service is delivered by Company to Customer, to be known as "delivery point," shall be the point at which the Customer's facilities are connected to the Company's facilities. The Company shall not be liable for any loss, injury, or damage resulting from the Customer's use of their equipment or occasioned by the energy furnished by the Company beyond the delivery point.

The Customer shall provide and maintain suitable protective devices on their equipment to prevent any loss, injury or damage that might result from single phasing conditions or any other fluctuation or irregularity in the supply of energy. The Company shall not be liable for any loss, injury or damage resulting from a single phasing condition or any other fluctuation or irregularity in the supply of energy which could have been prevented by the use of such protective devices.

The Company will provide and maintain the necessary line or service connections, transformers (when same are required by conditions of contract between the parties thereto), meters and other apparatus, which may be required for the proper measurement of and protection to its service. All such apparatus shall be and remain the property of the Company.

8. **CUSTOMER'S LIABILITY.**

In the event of loss or injury to the property of the Company through misuse by, or the negligence of, the Customer or the employees of the same, the cost of the necessary repairs or replacement thereof shall be paid to the Company by the Customer.

Customers will be responsible for tampering with, interfering with, or breaking of seals of meters, or other equipment of the Company installed on the Customer's premises. The Customer hereby agrees that no one except the employees of the Company shall be allowed to make any internal or external adjustments of any meter or any other piece of apparatus, which shall be the property of the Company.

The Company shall have the right at all reasonable hours to enter the premises of the Customer for the purpose of installing, reading, removing, testing, replacing or otherwise disposing of its apparatus and property, and the right of entire removal of the Company's property in the event of the termination of the contract for any cause.

9. **EXTENSION OF SERVICE.**

The electric facilities of the Company shall be extended or expanded to supply electric service to all residential Customers and small commercial Customers which require single phase line where the installed transformer capacity does not exceed 25 KVA in accordance with 807 KAR 5:041, Section 11.

The electric facilities of the Company shall be extended or expanded to supply electric service to Customer's other than those named in the above paragraph when the estimated revenue is sufficient to justify the estimated cost of making such extensions or expansions as set forth below.

For service to be delivered to Commercial, Industrial, Mining and multiple housing project Customers up to and including estimated demands of 500 KW requiring new facilities, the Company will: (a) where the estimated revenue for one year exceeds the estimated installed cost of new local facilities required, provide such new facilities at no cost to the Customer; (b) where the estimated revenue for one year is less than the installed cost of new local facilities required, the Customer will be required to pay a contribution in aid of construction equal to the difference between the installed cost of the new facilities required to serve the load and the estimated revenue for one year; (c) if the Company has reason to question the financial stability of the Customer and/or the life of the operation is uncertain or temporary in nature, such as construction projects, oil and gas well drilling, sawmills and mining operations, the Customer shall pay a contribution in aid of construction, consisting of the estimated labor cost to install and remove the facilities required plus the cost of unsalvageable material, before the facilities are installed.

(Cont'd on Sheet No. 2-6)

TERMS AND CONDITIONS OF SERVICE (Cont'd)

9. **EXTENSION OF SERVICE (Cont'd)**

For service to be delivered to Customers with demand levels higher than those specified above, the annual cost to serve the Customer's requirements shall be compared with the estimated revenue for one year to determine if a contribution in aid of construction, and/or a special minimum and/or other arrangement may be necessary. The annual cost to service shall be the sum of the following components:

1. The annual fixed costs of the generation, transmission and distribution facilities related to the Customer's requirements. These fixed costs will be calculated at 21.95% of the value to be based on the year-end embedded investment depreciated in all similar facilities of the Company.

2. The annual energy costs based on the latest available production costs related to the Customer's estimated annual energy use requirements.

3. The annual fixed costs of the new local facilities necessary to provide the service requested calculated at 21.95% of the installed cost of such facilities.

If the estimated revenue for one year is greater than the cost to serve as described herein, the Company may provide any new local facilities required at no cost to the Customer. If the estimated revenue for one year is less than the cost to serve as described herein, the Company will require the Customer to pay a contribution in aid of construction equal to the difference between the annual cost to serve as calculated and the estimated revenue for one year divided by 21.95%, but in no case to exceed the installed cost of the new facilities required. If, however, the annual cost to serve excluding the cost of new facilities paid for by the Customer, exceeds the estimated revenue for one year, the Company, will, in addition to a contribution in aid of construction, require a special minimum or other arrangement to compensate the Company for such deficiency in revenue. (T)

Except where service is rendered in accordance with 807 KAR 5:041, Section 11, as described herein, the Company may require the Customer to execute an Advance and Refund Agreement where the Company reasonably questions the longevity of the service or the estimated energy use and demand requirements provided by the Customer. Under the Advance and Refund Agreement, the Customer shall pay the Company the estimated total installed cost of the required new facilities which advance could be refunded over a five-year period under certain conditions. Over the five year period the Customer's electric bill would be credited each month up to the amount of 1/60th of the total amount advanced. Such credit shall be applied only to that portion of the Customer's bill, which exceeds a specified minimum. The specified minimum before refund shall be established as the greater of: (1) the minimum as described under the applicable tariff or (2) the amount representing 1/12th of the calculated annual cost to serve as described herein. In the event the Customer's monthly bill in any month does not exceed such minimum by an amount equal to 1/60th of the amount advanced, the difference between 1/60th of the amount advanced and the amount, if any, actually credited to the Customer's bill shall be designated as "accrued credit" and applied to future monthly bills over the balance of the 5 year period as credit where such monthly bills exceed the established minimum by more than 1/60th of the amount advanced. (T)

10. **EXTENSION OF SERVICE TO MOBILE HOME.**

The electrical facilities of the Company will be extended or expanded to supply electric service to mobile homes in accordance with 807 KAR 5:041, Section 12.

11. **LOCATION AND MAINTENANCE OF COMPANY'S EQUIPMENT.**

The Company shall have the right to construct its poles, lines and circuits on the property, and to place its transformers and other apparatus on the property or within the building of the Customer, at a point or points convenient for such purposes, as required to serve such Customer, and the Customer shall provide suitable space for the installation of necessary measuring instruments so that the latter may be protected from injury by the elements or through the negligence or deliberate acts of the Customer or of any employee of the same.

(Cont'd on Sheet No. 2-7)

TERMS AND CONDITIONS OF SERVICE (Cont'd)

12. **BILLING FORM.**

Pursuant to 807 KAR 5:006, Section 6(3) copies of the billing forms used by the Company are shown on Sheet Nos. 2-11, 2-12 and 2-13.

13. **RATE SCHEDULE SELECTION.**

The Company will explain to the Customer, at the beginning of service or upon request the Company's rates available to the Customer. Company will assist Customer in the selection of the rate schedule best adapted to Customer's service requirements, provided, however, that Company does not assume responsibility for the selection or that Customer will at all times be served under the most favorable rate schedule. (T)

Customer may change their initial rate schedule selection to another applicable rate schedule at any time by either written notice to Company and/or by executing a new contract for the rate schedule selected, provided that the application of such subsequent selection shall continue for 12 months before any other selection may be made. In no case will the Company refund any monetary difference between the rate schedule under which service was billed in prior periods and the newly selected rate schedule.

14. **MONITORING USAGE.**

At least once annually the Company will monitor the usage of each customer according to the following procedure:

1. The Customer's monthly usage will be compared with the usage of the corresponding period of the previous year.
2. If the monthly usage for the two periods are substantially the same or if any difference is known to be attributed to unique circumstances, such as unusual weather conditions, common to all customers, no further review will be made.
3. If the monthly usage is not substantially the same and cannot be attributed to a readily identified common cause, the Company will compare the Customer's monthly usage records for the 12-month period with the monthly usage for the same months of the preceding year.
4. If the cause for the usage deviation cannot be determined from analysis of the Customer's meter reading and billing records, the Company will contact the Customer to determine whether there have been changes that explain the increased or decreased usage.
5. Where the deviation is not otherwise explained, the Company will test the Customer's meter to determine whether it shows an average error greater than 2 percent fast or slow.
6. The Company will notify the customers of the investigation, its findings, and any refunds or back billing in accordance with 807 KAR 5:006, Section 10(4) and (5).

In addition to the annual monitoring, the Company will immediately investigate usage deviations brought to its attention as a result of its on-going meter reading, billing processes, or customer inquiry.

(Cont'd on Sheet No. 2-8)

KENTUCKY POWER COMPANY

Original Sheet No. 2-8
Canceling ______ Sheet No. 2-8

P.S.C. ELECTRIC NO. 8

TERMS AND CONDITIONS OF SERVICE (Cont'd)

15. **USE OF ENERGY BY CUSTOMER**

The tariffs for electric energy given herein are classified by the character of use of such energy and are not available for service except as provided herein.

Upon the expiration of an electric service contract, if required by the terms of the tariff, the Customer may elect to renew the contract upon the same or another tariff published by the Company available to the Customer and applicable to the Customer's requirements, except that in no case shall the Company be required to maintain transmission, switching or transformation equipment different from or in addition to that generally furnished to other Customers receiving electrical supply under the terms of the tariff elected by the Customer. (T)

The service connections, transformers, meters and appliances supplied by the Company for each Customer have a definite capacity and no additions to the equipment, or load connected thereto, will be allowed except by consent of the Company.

The Customer shall install only motors, apparatus or appliances which are suitable for operation with the character of the service supplied by the Company, and which shall not be detrimental to same, and the electric energy must not be used in such a manner as to cause unprovided for voltage fluctuations or disturbances in the Company's transmission or distribution system. The Company shall be the sole judge as to the suitability of apparatus or appliances, and also as to whether the operation of such apparatus or appliances is or will be detrimental to its general service.

No attachment of any kind whatsoever may be made to the Company's lines, poles, cross arms, structures or other facilities without the express written consent of the Company.

All apparatus used by the Customer shall be of such type as to secure the highest practicable commercial efficiency, power factor and the proper balancing of phases. Motors which are frequently started or motors arranged for automatic control must be of a type to give maximum starting torque with minimum current flow, and must be of a type, and equipped with controlling devises, approved by the Company. The Customer agrees to notify the Company of any increase or decrease in his connected load.

The Company will not supply service to Customers who have other sources of electrical energy supply except under tariffs, which specifically provide for same.

The Customer shall not be permitted to operate generating equipment in parallel with the Company's service except with express written consent of the Company. (T)

Resale of energy will be permitted only with express written consent by the Company.

16. **RESIDENTIAL SERVICE.**

Individual residences shall be served individually with single-phase service under the applicable residential service tariff. Customer may not take service for 2 or more separate residences through a single point of delivery under any tariff. Exclusions may be allowed pursuant to 807 KAR 5:046 (Prohibition of master metering).

The residential service tariff shall cease to apply to that portion of a residence which becomes regularly used for business, professional, institutional or gainful purposes, which requires three phase service or which requires service to motors in excess of 10 HP each. Under these circumstances, Customer shall have the choice of: (1) of separating the wiring so that the residential portion of the premises is served through a separate meter under the residential service tariff and the other uses as enumerated above are served through a separate meter or meters under the applicable general service tariff; or (2) taking the entire service under the applicable general service tariff.

Detached building or buildings, actually appurtenant to the residence, such as a garage, stable or barn, may be served by an extension of the Customer's residence wiring through the residence meter and under the applicable residential service tariff.

(Cont'd on Sheet No. 2-9)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E.K. WAGNER (NAME) DIRECTOR OF REGULATORY SERVICES (TITLE) FRANKFORT, KENTUCKY (ADDRESS)

Issued by authority of an Order of the Public Service Commission in Case No. 2005- dated

TERMS AND CONDITIONS OF SERVICE (Cont'd)

17. **DENIAL OR DISCONTINUANCE OF SERVICE.**

The Company reserves the right to refuse to serve any applicant for service or to discontinue to serve any Customer if the applicant or Customer is indebted to the Company for any service theretofore rendered at any location; provided however, the Customer shall be notified in writing in accordance with 807 KAR 5:006, Section 14, before disconnection of service.

The Company reserves the right to discontinue to serve any Customer for failure to provide and maintain adequate security for the payment of bills as requested by the Company, for failure to comply with these terms and conditions or to prevent fraud upon the Company.

Any discontinuance of service shall not terminate the contract for electric service between the Company and the Customer nor shall it abrogate any minimum charge, which may be effective.

18. **EMPLOYEES' DISCOUNT.**

Regular employees who have been in the Company's employ for 6 months or more may, at the discretion of the Company, receive a reduction in their residence electric bills for the premises occupied by the employee.

19. **SPECIAL CHARGES.**

A. Reconnection and Disconnect Charges

In cases where the Company has discontinued service as herein provided for, the Company reserves the right to assess a reconnection charge pursuant to 807 KAR 5:006, Section 8 (3)(b), payable in advance, in accordance with the following schedule. However, those Customers qualifying for Winter Hardship Reconnection under 807KAR5:006 Section 15 shall be exempt from the reconnect charges.

1. Reconnect for nonpayment during regular hours..........................~~$9.00~~ *$38.00* (I)
2. Reconnect for nonpayment when work continues into overtime
   At the end of the day (No "Call Out" required)...........................~~$12.00~~ *$42.00* (I)
3. Reconnect for nonpayment when a "Call Out" is required
   (A "Call Out" is when an employee must be called in to work
   on an overtime basis to make the reconnect trip)..........................~~$25.00~~ *$76.00* (I)
4. Reconnect for nonpayment when double time is required
   (Sunday and Holiday).. ~~$31.00~~ *$100.00* (I)
5. Termination or field trip...$ ~~6.00~~ *$23.00* (I)

The reconnection charge for all Customers where service has been disconnected for fraudulent use of electricity will be the actual cost of the reconnection.

(Cont'd on Sheet No. 2-10)

TERMS AND CONDITIONS OF SERVICE (Cont'd)

19. SPECIAL CHARGES (Cont'd).

B. Returned Check Charge

In cases where a customer pays by check, which is later returned as unpaid by the bank for any reason, the Customer will be charge a fee of ~~$5.00~~ *$7.00* to cover the handling costs. (I)

C. Meter Test Charge

Where test of a meter is made upon written request of the Customer pursuant to 807 KAR 5:006, Section 18, the Customer will be charged ~~$10.00~~ *$69.00* if such tests shows that the meter was not more than two percent (2%) fast. (I)

D. Work Performed on Company's Facilities at Customer's Request

Whenever, at the request and for the benefit of the Customer, work is performed on the Company's facilities, including the relocation, or replacement of the Company's facilities, the Customer shall pay to the Company in advance of the Company undertaking the work the estimated total cost of such work. This cost shall be itemized by major categories and shall include the Company's overheads and shall be credited with the net value of any salvageable material. The actual cost for the work performed shall be calculated at the completion of the work and the appropriate charge or refund will be made to the Customer.

Reasonable notice of not less than three working days shall be given to the Company for all requested work except for the covering of the Company's lines. Notice of any request for the Company to cover its lines shall be given at least two days in advance. The Company will endeavor to comply with all timely requests, but work may be delayed because of demands on the Company's personnel and equipment.

If the cost, as calculated above, is $500 or less for covering the Company's distribution facilities no charge will be imposed. All costs in excess of $500 for covering the Company's distribution facilities, shall be paid by the Customer, in advance of the Company undertaking the work. The actual cost for the work performed shall be calculated at the completion of the work and the appropriate charge or refund will be made to the customer. (T)

(Cont'd on Sheet No. 2-11)

KENTUCKY POWER COMPANY

Original Sheet No. 2-11
Canceling ______ Sheet No. 2-11

P.S.C. ELECTRIC NO. 8

TERMS AND CONDITIONS OF SERVICE (Cont'd)

Residential and Small Commercial Bill Form

AEP KENTUCKY POWER
A unit of American Electric Power

Send Inquiries To:
PO BOX 24401
CANTON, OH 44701-4401
039-999-999-9-9 CYC 19

Total Amount Due [illegible] $XXX.XX
Due Date: June 10; Add $XXX After June 2[illegible]

Amount Enclosed

Make Check Payable and Send To:
039-999-999-9-9 CYC 19
KENTUCKY POWER COMPANY
P.O. BOX 24417
CANTON OHIO 44701-4417

KPCO Consumer
123 ANY ADDRESS
AEP CITY, KY 99999-9999

00000649000000649000000000000399999999922021403018103805

Please tear on dotted line and return top portion with your payment

SERVICE AT [illegible] Questions About Bill [illegible] or Service Call [illegible] 1-800-572-1113
KPCO Consumer
123 ANY ADDRESS Pay by Phone [illegible] Bill Date 05/25/05
AEP CITY, KY 99999-9999 1-877-308-9280 [illegible]

Account Number
039-999-999-9-9

PREVIOUS CHARGES	Account Balance	Amount Due
Total Amount Due at Last Billing	$ XXX.XX	
Payment 05/05/05 - Thank You	XXX.XX CR	
Previous Balance	$ XXX.XX	$ XXX.XX

CURRENT KPCO CHARGES (1-800-572-1113):		
05/25/05 Tariff 015 - RESIDENTIAL SERVICE		
Rate Billing	$ XX.XX	
Fuel Adj @ 0.0XXXXXX Per KWH	X.XX	
DSM Adj @ 0.0XXXXXX Per KWH	XX.XX	
Net Merger Cr @ 0.0XXXXXX Per KWH	X.XX	
State Issues Settlement @ 0.0XXXXXX Per KWH	X.XX	
Environmental Adj X.XXXXXXX%	X.XX	
School Tax	X.XX	
Current Electric Due	$ XXX.XX	$ XXX.XX

Total Amount Due [illegible] $XXX.XX
Due Date June 10; Add $XXX After June 2[illegible]

Average energy cost per KWH = $X.XX

USAGE:

Meter Number	Service Period From	Service Period To	Meter Reading Prev	CD	Pres	CD	Multiplier	Metered Usage
99999999	4/26/2005	5/25/2005	76755	A	77501	A	1.0000	746 KWH

CD - Read Code: A= Actual Reading   29 Billing Days   Next Reading Date 06/24/05

KPCO MESSAGES:
You may view detail rate information online at http://www.aepcustomer.com/tariffs/default.htm.
Visit us at www.KentuckyPower.com

AEP KENTUCKY POWER
A unit of American Electric Power
Rates Available on Request
See other side for

(Cont'd on Sheet No. 2-12)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E. K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2005- dated

KENTUCKY POWER COMPANY

Original Sheet No. 2-12
Canceling ______ Sheet No. 2-12

P.S.C. ELECTRIC NO. 8

TERMS AND CONDITIONS OF SERVICE (Cont'd)

Large Commercial and Industrial Bill Form – Page 1

AEP KENTUCKY POWER
A unit of American Electric Power

Send Inquiries To:

PO BOX 24401
CANTON, OH 44701-4401
039-999-999-9-9 CYC 01

Total Amount Due $XXXX.XX
Due Date June 16, add $XXX.XX After This Date

Amount Enclosed

Make Check Payable and Send To:
039-999-999-9-9 CYC 01
KENTUCKY POWER COMPANY
P.O. BOX 24417
CANTON OHIO 44701-4417

KPCO Consumer
123 ANY ADDRESS
AEP CITY, KY 99999-9999

000006490000006490000000000003999999999220214030181038O5

Please tear on dotted line and return top portion with your payment

SERVICE AT:
KPCO Consumer
123 ANY ADDRESS
AEP CITY, KY 99999-9999

Questions About Bill or Service Call: 1-800-572-1110
Pay by Phone: 1-877-308-9280

Account Number
039-999-999-9-9

Bill Date 05/31/05
Page 1 of 2

PREVIOUS CHARGES		Account Balance		Amount Due
Total Amount Due at Last Billing	$	XXXX.XX		
Payment 05/17/05 - Thank You		XXXX.XX CR		
Previous Balance	$	XXXX.XX	$	XXXX.XX

CURRENT KPCO CHARGES (1-888-710-4237):

04/29/04 Tariff 240 - LARGE GENERAL SERVICE				
Rate Billing	$	XXXX.XX		
Fuel Adj @ 0.0XXXXXX Per KWH		XXX.XX		
Net Merger Cr @ 0.0XXXXXX Per KWH		XX.XX		
State Issues Settlement @ 0.0XXXXXX Per KWH		XX.XX		
Environmental Adj X.XXXXXXX%		XXX.XX		
School Tax		XX.XX		
State Sales Tax		XXX.XX		
Current Electric Due	$	XXXX.XX	$	XXXX.XX

Total Amount Due $XXXX.XX
Due June 16, Add XXX.XX After This Date

Average energy cost per KWH = $x.xx

USAGE:

Meter Number	Service Period From	Service Period To	Meter Reading Prev	CD	Pres	CD	Multiplier	Metered Usage
99999999	4/29/2005	5/31/2005	XXXXX	A	XXXXX	A	XXX.XXXX	XXXXX KWH
99999999	4/29/2005	5/31/2005		A	XXXXX	A	XXX.XXXX	XXX.XX KW
99999999	4/29/2005	0531/05	XXXXX	A	XXXXX	A	XXX.XXXX	XXXXX KVARH

CD - Read Code: A= Actual Reading   32 Billing Days   Next Reading Date 06/29/05

AEP KENTUCKY POWER
A unit of American Electric Power

Rates Available on Request

See other side for Important Information

(Cont'd on Sheet No. 2-13)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E. K. WAGNER (NAME) DIRECTOR OF REGULATORY SERVICES (TITLE) FRANKFORT, KENTUCKY (ADDRESS)

Issued by authority of an Order of the Public Service Commission in Case No. 2005- dated

KENTUCKY POWER COMPANY

Original Sheet No. 2-13
Canceling ______ Sheet No. 2-13

P.S.C. ELECTRIC NO. 8

TERMS AND CONDITIONS OF SERVICE (Cont'd)

Large Commercial and Industrial Bill Form – Page 2

AEP KENTUCKY POWER
A unit of American Electric Power

Send Inquiries To:

PO BOX 24401
CANTON, OH 44701-4401
039-999-999-9-9 CYC 01

SERVICE AT:
KPCO CONSUMER
123 ANY ADDRESS
AEP CITY, KY 99999-9999

Questions About Bill
or Service Call:
1-800-572-[illegible]
Pay by Phone:
1-877-306-[illegible]

Account Number
039-999-999-9-9

Bill Date 05/31/05
Page 2 of 2

Please return the payment stub on Page 1 with your payment.

ADJUSTED USAGE

Metered Usage	Power Factor	Power Factor Constant	Comp Meter Multiplier	Billing Usage
				XXXXX KWH
				XXX.XX KW
				XXXXX KVARH

Contract Capacity = XXX.X

High Prev Demand = On-Pk
Off-Pk

KPCO MESSAGES:

You may view detail rate information online at http://www.aepcustomer.com/tariffs/default.htm.

Visit us at www.KentuckyPower.com

AEP KENTUCKY POWER
A unit of American Electric Power

Rates Available on Request

See other side for important information

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E. K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2005- dated

CAPACITY AND ENERGY CONTROL PROGRAM

The Company's Capacity and Energy Control Program consists of:

I. Procedures During Abnormal System Frequency (T)

II. Capacity Deficiency Program

III. Energy Emergency Control Program

A copy of the Company's Emergency Operating Plan was filed with the Kentucky Public Service Commission on October 22, 2004 in Administrative Case No. 353 in compliance with the Commission's Order dated January 20, 1995.

I. PROCEDURES DURING ABNORMAL SYSTEM FREQUENCY

A. INTRODUCTION

Precautionary procedures are required to meet emergency conditions such as system separation and operation at subnormal frequency. In addition, the coordination of these emergency procedures with neighboring companies is essential. The AEP program, which is in accordance with ECAR Document 3, is noted below.

B. PROCEDURES AEP/PJM

1. From 59.8 – 60.2 Hz to the extent practicable utilize all operating and emergency reserves. The manner of utilization of these reserves will depend greatly on the behavior of the System during the emergency. For rapid frequency decline, only that capacity on-line and automatically responsive to frequency (spinning reserve), and such items as interconnection assistance and load reductions by automatic means are of assistance in arresting the decline in frequency.

   If the frequency decline is gradual, the Generation/Production Optimization Group, particularly in the deficient area, should invoke non-automatic procedures involving operating and emergency reserves. These efforts should continue until the frequency decline is arrested or until automatic load-shedding devices operate at subnormal frequencies.

2. At 59.75 Hz
   a. Suspend Automatic Generation Control (AGC)
   b. Notify Interruptible Customers to drop load

3. At 59.5 Hz automatically shed 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

4. At 59.4 Hz automatically shed an additional 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

5. At 59.3 Hz automatically shed an additional 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

6. At 59.1 Hz automatically shed an additional 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

7. At 59.0 Hz automatically shed an additional 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

8. At 58.9 Hz automatically shed an additional 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

9. At 58.2 Hz automatically trip the D.C. Cook Nuclear Units 1 and 2.

10. At 58.0 Hz or at generator minimum turbine off-frequency value, isolate generating unit without time delay.

If at any time in the above procedure the decline in area frequency is arrested below 59.0 Hz, that part of the System in the low frequency area should shed an additional 10% of its initial load. If, after five minutes, this action has not returned the area frequency to 59.0 Hz or above, that part of the System shall shed an additional 10% of its remaining load and continue to repeat in five-minute intervals until 59.0 Hz is reached. These steps must be completed within the time constraints imposed upon the operation of generating units. (T)

(Cont'd on Sheet No. 3-2)

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

II. CAPACITY DEFICIENCY PROGRAM

A. PURPOSE

To provide a plan for full utilization of emergency capacity resources and for orderly reduction in the aggregate customer demand on the American Electric Power AEPEast/PJM System in the event of a capacity deficiency. (T)

B. CRITERIA

The goals of AEP are to safely and reliably operate the interconnected network in order to avoid widespread system outages as a consequence of a major disturbance. Precautionary procedures including maintaining Daily Operating Reserves, as specified in ECAR document 2 and PJM Manual M13, will assist in avoiding serious emergency conditions such as system separation and operation at abnormal frequency. However, adequate Daily Operating Reserves cannot always be maintained, so the use of additional emergency measures may be required. A Capacity Deficiency is a shortage of generation versus load and can be caused by generating unit outages and/or extreme internal load requirements. (T)

C. AEP EAST/PJM PROCEDURES

(note: the following section contains excerpts from PJM Manual – M13) (T)

OVERVIEW

PJM is responsible for determining and declaring that an Emergency is expected to exist, exists, or has ceased to exist in any part of the PJM RTO or in any other Control Area that is interconnected directly or indirectly with the PJM RTO. PJM directs the operations of the PJM Members as necessary to manage, allocate, or alleviate an emergency.

- *PJM RTO Reserve Deficiencies* — If PJM determines that PJM-scheduled resources available for an Operating Day in combination with Capacity Resources operating on a self-scheduled basis are not sufficient to maintain appropriate reserve levels for the PJM RTO, PJM performs the following actions:
- Recalls energy from Capacity Resources that otherwise deliver to loads outside the Control Area and dispatches that energy to serve load in the Control Area.
- Purchases capacity or energy from resources outside the Control Area. PJM uses its best efforts to purchase capacity or energy at the lowest prices available at the time such capacity or energy is needed. The price of any such capacity or energy is not considered in determining Locational Marginal Prices in the PJM Energy Market. The cost of capacity or energy is allocated among the Market Buyers as described in the PJM Manual for Operating Agreement Accounting (M-28)

The AEP System Control Center will be referred to as SCC and the AEP Production Optimization Group will be referred to as POG.

CAPACITY SHORTAGES

PJM is responsible for monitoring the operation of the PJM RTO, for declaring the existence of an Emergency, and for directing the operations of the PJM Member as necessary to manage, alleviate, or end an Emergency. PJM also is responsible for transferring energy on the PJM Members behalf to meet an Emergency. PJM is also responsible for agreements with other Control Areas interconnected with the PJM RTO for the mutual provision of service to meet an Emergency.
Exhibit 1 illustrates that there are three general levels of emergency actions for capacity shortages:

- alerts
- warnings
- actions

ALERTS

The intent of the alerts is to keep all affected system personnel aware of the forecast and/or actual status of the PJM RTO. All alerts and cancellation thereof are broadcast on the "ALL-CALL" system and posted to selected PJM web sites to assure that all members receive the same information.
Alerts are issued in advance of a scheduled load period to allow sufficient time for members to prepare for anticipated initial capacity shortages. (T)

(Cont'd on Sheet 3-3)

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

AEP East/PJM Procedures (cont'd) (T)

Alerts(Cont'd)

Maximum Emergency Generation Alert
The purpose of the Maximum Emergency Generation Alert is to provide an early alert that system conditions may require the use of the PJM emergency procedures. It is implemented when Maximum Emergency Generation is called into the operating capacity.

Primary Reserve Alert
The purpose of the Primary Reserve Alert is to alert members of the anticipated shortage of operating reserve capacity for a future critical period. It is implemented when estimated operating reserve capacity is less than the forecast primary reserve requirement.

Voltage Reduction Alert
The purpose of the Voltage Reduction Alert is to alert members that a voltage reduction may be required during a future critical period. It is implemented when the estimated operating reserve capacity is less than the forecast spinning reserve requirement.

Voluntary Customer Load Curtailment Alert
The purpose of the Voluntary Customer Load Curtailment Alert is to alert members of the probable future need to implement a voluntary customer load curtailment. It is implemented whenever the estimated operating reserve capacity indicates a probable future need for voluntary customer load curtailment.

Warnings

Warnings are issued during present operations to inform members of actual capacity shortages or contingencies that may jeopardize the reliable operation of the PJM RTO. The intent of warnings is to keep all affected system personnel aware of the forecast and/or actual status of the PJM RTO. All warnings and cancellations are broadcasted on the "ALL-CALL" system and posted to selected PJM web sites to assure that all members receive the same information.

Primary Reserve Warning
The purpose of the Primary Reserve Warning is to warn members that the available primary reserve is less than required and present operations are becoming critical. It is implemented when available primary reserve capacity is less than the primary reserve requirement, but greater than the spinning reserve requirement, after all available secondary reserve capacity (except restricted maximum emergency capacity) is brought to a primary reserve status and emergency operating capacity is scheduled from adjacent systems.

Voltage Reduction Warning & Reduction of Non-Critical Plant Load
The purpose of the Voltage Reduction Warning & Reduction of Non-Critical Plant Load is to warn members that the available spinning reserve is less than the Spinning Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required. It is implemented when the available spinning reserve capacity is less than the spinning reserve requirement, after all available secondary and primary reserve capacity (except restricted maximum emergency capacity) is brought to a spinning reserve status and emergency operating capacity is scheduled from adjacent systems.

Manual Load Dump Warning
The purpose of the Manual Load Dump Warning is to warn members of the increasingly critical condition of present operations that may require manually dumping load. It is issued when available primary reserve capacity is less than the largest operating generator or the loss of a transmission facility jeopardizes reliable operations after all other possible measures are taken to increase reserve. The amount of load and the location of areas(s) are specified.

Actions

The PJM RTO is normally loaded according to bid prices; however, during periods of reserve deficiencies, other measures must be taken to maintain system reliability. These measures involve:

- Loading generation that is restricted for reasons other than cost
- Recalling non-capacity backed off-system sales
- Purchasing emergency energy from participants / surrounding pools
- Load relief measures (T)

(Cont'd on Sheet No. 3-4)

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

AEP East/PJM Procedures (Cont'd) (T)

Actions (Cont'd)

The procedures to be used under these circumstances are described in the general order in which they are applied. Due to system conditions and the time required to obtain results, PJM dispatcher may find it necessary to vary the order of application to achieve the best overall system reliability. Issuance and cancellation of emergency procedures are broadcast over the "ALL-CALL" and posted to selected PJM web sites. Only affected systems take action. PJM dispatcher broadcasts the current and projected PJM RTO status periodically using the "ALL-CALL" during the extent of the implementation of the emergency procedures.

Maximum Emergency Generation
The purpose of the Maximum Emergency Generation is to increase the PJM RTO generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the highest incremental cost level.

Load Management Curtailments (ALM)

Steps 1 and 2 (PJM Control)
The purpose of the Load Management Curtailments, Steps 1 and 2, is to provide additional load relief by using PJM controllable load management programs. Steps 1 and 2 are differentiated only by the expected time to implement. Load relief is required after initiating Maximum Emergency Generation.

Step 1: Short Time Frame to Implement (1 Hour or Less)
- PJM dispatcher requests members to implement Load Management Curtailment, Step 1.

Step 2: Long Time Frame To Implement (Greater Than 1 Hour)
- PJM dispatcher requests members to implement Load Management Curtailment, Step 2.

Steps 3 and 4 (SCC Control)
The purpose of the Local Control Center Programs of Load Management Curtailments, Steps 3 and 4, is to provide additional load relief by requesting use of Local Control Center load management programs.

Load Reduction Program
The purpose of the Load Reduction Action is to request end-use customers to reduce load during emergency conditions.

Voltage Reduction
The purpose of Voltage Reduction during capacity deficient conditions is to reduce load to provide a sufficient amount of reserve to maintain tie flow schedules and preserve limited energy sources. A curtailment of non-essential building load is implemented prior to or at this same time as a Voltage Reduction Action. It is implemented when load relief is still needed to maintain tie schedules.

> **Note:** Voltage reductions can also be implemented to increase transmission system voltage.

> **Note:** Curtailment of non-essential building load may be implemented prior to, but not later than, the same time as a voltage reduction.

Curtailment of Non-Essential Building Load
The purpose of the Curtailment of Non-Essential Building Load is to provide additional load relief, to be expedited prior to, but no later than the same time as a voltage reduction. (T)

(Cont'd on sheet No. 3-5)

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

AEP East/PJM Procedures (cont'd)

Actions (cont'd)

Voluntary Customer Load Curtailment
The purpose of the Voluntary Customer Load Curtailment (VCLC) is to provide further load relief. It is implemented when the estimated peak load minus the relief expected from curtailment of non-essential building load and a 2.5% - 5% voltage reduction is greater than operating capacity.

PJM/SCC – Public Appeal to conserve electricity usage

Manual Load Dump
The purpose of the Manual Load Dump is to provide load relief when all other possible means of supplying internal PJM RTO load have been used to prevent a catastrophe within the PJM RTO or to maintain tie schedules so as not to jeopardize the reliability of the other interconnected regions. It is implemented when the PJM RTO cannot provide adequate capacity to meet the PJM RTO's load or critically overloaded transmission lines or equipment cannot be relieved in any other way and/or low frequency operation occurs in the PJM RTO, parts of the PJM RTO, or PJM RTO and adjacent Control Areas that may be separated as an island.

Addendum to Manual Load Dump Procedures

AEP understands that PJM intends to implement these curtailment protocols consistent with the agreements that PJM entered into in Kentucky and Virginia, in Stipulations approved by the Kentucky Public Service Commission and Virginia State Corporation Commission (with modifications) in Case No. 2002-00475 and Case No. PUE-2000-00550, respectively.

Capacity Deficiency Summary

A summary of the emergency alerts, warning and actions, together with the typical sequence and the method of communication, are presented in the following Table III-2 on Tariff Sheet No. 3-6.

(Cont'd on Sheet No. 3-6)

KENTUCKY POWER COMPANY

Original SHEET NO. 3-6
CANCELING SHEET NO. 3-6

P.S.C. ELECTRIC NO. 8

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

(T)

		Communications	Description	
Alert	Maximum Emergency Generation	PJM-POG via All-Call PJM-SCC via All-Call SCC-TDC	SCC/POG review scheduled or actual maintenance affecting capacity or critical transmission to determine if it can be deferred or cancelled	**EEA 1**
	Primary Reserve	PJM-POG via All-Call PJM-SCC via All-Call SCC-TDC	(Same as above)	
	Voltage Reduction	PJM-SCC via All-Call SCC-TDC	SCC/TDC to identify stations for Voltage Reduction	
	Voluntary Customer Load Curtailment	PJM-POG via All-Call PJM-SCC via All-Call	Not Applicable	
Warning	Primary Reserve	PJM-POG via All-Call PJM-SCC via All-Call SCC-TDC	SCC/POG ensure that all deferrable maintenance or testing affecting capacity or critical transmission is halted.	
	Voltage Reduction & Reduction of Non-Critical Plant Load	PJM-POG via All-Call PJM-SCC via All-Call SCC-TDC	SCC to inform TDC to man Voltage Reduction Stations & prepare for Voltage Reduction	POG to reduce plant load. (See Table III-4)
	Manual Load Dump	PJM-SCC via All-Call SCC– POG-Environmental Services SCC-TDC-DDC	Lifting of Environmental Restrictions (See Table III-5)	Manual & Automatic Load Shedding
		Make preparations for a Public Appeal if one becomes necessary.	a. Obtain permission to exceed opacity limits b. Obtain permission to exceed heat input limits c. Obtain permission to exceed river temperature limits	SCC/TDC will review local computer procedures and man manual load shedding stations
Action	Maximum Emergency Generation	PJM-POG via All-Call PJM-SCC via All-Call	Supplemental Oil & Gas Firing; Operate Generator Peakers; Emergency Hydro; Extra Load Capability	See Table III-3
	Load Management Curtailment (ALM)	PJM-SCC via All-Call SCC - POG	Step 3 – 1267 Mws – 1 hr, 249 Mws – 2 hr	**EEA 2 (DOE Report)**
	Load Reduction Program	PJM-SCC via All-Call	Not Applicable	
	Voltage Reduction	PJM-SCC via All-Call SCC –TDC & SCC - POG	Initiate Voltage Reduction - AEP/PJM – 64 Mws	
	Curtailment of Non-Essential Building Load	PJM-POG via All-Call PJM-SCC via All-Call SCC- Building Services	Initiate curtailment of AEP building load – 4.4 Mws	Issued approx. same time as Voltage Reduction
	Voluntary Customer Load Curtailment	PJM-POG via All-Call PJM-SCC via All-Call	Not Applicable	**EEA 3 (DOE Report)**
	Public Appeal (may be issued at any stage of the Action items)	SCC – Corporate Communications	a. Radio and TV alert to general public	2% of AEP Internal Load
		SCC – Customer Services SCC - POG	b. Call to Industrial and Commercial Customers	1276 Mws - 1 hr + 320 Mws - 2 hr
		SCC - TDC	c. Municipal and REMC Customers	7% of Cust. Load
	Manual Load Dump	PJM-SCC via All-Call SCC-POG-Environmental Services SCC-TDC-DDC	PJM Allocation based on deficient zones	
			a. Lift Environmental Restrictions on units	(regains curtailed generation)
			b. Selected distribution customers (manual load curtailment)	Execute MLD

(T)

(Cont'd on Sheet 3-7)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E. K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order at the Public Service Commission in Case No. 2005- dated

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

Energy Emergency Alert Levels (reference NERC Appendix 5C) (T)

1. Alert 1 - All available resources in use.

   Circumstances:
   - Control Area, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. Alert 2 - Load management procedures in effect.

   Circumstances:
   - Control Area, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
   - Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
     - Voltage reduction
     -
     - Public appeals to reduce demand
     - Interruption of non-firm end use loads in accordance with applicable contracts, for emergency, not economic reasons
     - Demand-side management
     - Utility load conservation measures
   - During Alert 2, The Reliability Coordinators, Control Areas, and Energy Deficient Entities have the following responsibilities:

     2.1 Notifying other Control Areas and Market Participants.

     2.2 Declaration Period. The Energy Deficient Entity shall update the Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated.

     2.3 Share information on resource availability.

     2.4 Evaluating and mitigating transmission limitations.
     2.4.1 Notification of ATC adjustments.
     2.4.2 Availability of generation redispatch options.
     2.4.3 Evaluating impact of current Transmission Loading Relief events.
     2.4.4 Initiating inquiries on reevaluating Operating Security Limits.

     2.5 Coordination of emergency responses. The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.

     2.6 Energy Deficient Entity actions. Before declaring an Alert 3, the Energy Deficient Entity must make use of available resources. This includes but is not limited to:

     2.6.1 All available generation units are on line. All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.

     2.6.2 Purchases made regardless of cost. All firm and non-firm purchases have been made, regardless of cost. (T)

(Cont'd on Sheet No. 3-8)

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

Energy Emergency Alert Levels (reference NERC Appendix 5C) (Cont'd) (T)

2.6.3 Non-firm sales recalled and contractually interruptible loads and DSM curtailed. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and Demand-side Management activated within provisions of the agreements.

2.6.4 Operating Reserves. Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

3. Alert 3 - Firm load interruption imminent or in progress.

Circumstances:

- Control Area or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 Continue actions from Alert 2.

3.2 Declaration Period. The Energy Deficient Entity shall update the Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated.

3.3 Use of Transmission short-time limits.

3.4 Reevaluating and revising Operating Security Limits.

3.4.1 Energy Deficient Entity obligations. The deficient Control Area or Load Serving Entity must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding.

3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use his best efforts to ensure that revising Operating Security Limits would not result in any cascading failures within the Interconnection.

3.5 Returning to pre-emergency Operating Security Limits. Whenever energy is made available to an Energy Deficient Entity such that the transmission systems can be returned to their pre-emergency Operating Security Limits, the Energy Deficient Entity shall notify its respective Reliability Coordinator and downgrade the Alert.

3.5.1 Notification of other parties.

3.6 Reporting. Any time an Alert 3 is declared, the Energy Deficient Entity shall complete the report listed in NERC Appendix 9B, Section C and submit this report to its respective Reliability Coordinator within two business days of downgrading or termination of the Alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC web site. The Reliability Coordinator shall present this report to the Reliability Coordinator Working Group at its next scheduled meeting.

4. Alert 0 - Termination. When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of his Reliability Coordinator that the EEA be terminated.

4.1 Notification. (T)

(Cont'd on Sheet 3-9)

CAPACITY AND ENERGY CONTROL PROGRAM

III. ENERGY EMERGENCY CONTROL PROGRAM

A. INTRODUCTION

The purpose of this plan is to provide for the reduction of the consumption of electric energy on the American Electric Power Company System in the event of a fuel shortage, such as might result from a general strike, or severe weather. (T)

B. PROCEDURES

In the event of a potential severe coal shortage, such as one resulting from a general coal strike, the following steps will be implemented. These steps will be carried out to the extent permitted by contractual commitments or by order of the regulatory authorities having jurisdiction.

A. To be initiated when system fuel supplies are decreased to 70% of target days' operation of coal-fired generation and a continued downward trend in coal stocks is anticipated: (T)

1. Optimize the use of non-coal-fired generation to the extent possible.
2. For individual plants under 50% of minimum target days' supply, review the prudence of modifying economic dispatching procedures to conserve coal. (T)
3. If necessary discontinue all economy sales to neighboring utilities.
4. Curtail the use of energy in company offices, plants, etc., over and above the reductions already achieved by current in-house conservation measures.

B. To be initiated when system fuel supplies are decreased to 60% of target days' operation of coal-fired generation and a continued downward trend in coal stocks is anticipated: (T)

1. Substitute the use of oil for coal, as permitted by plant design, oil storage facilities, and oil availability.
2. Discontinue all economy and short-term sales to neighboring utilities.
3. Limit emergency deliveries to neighboring utilities to situations where regular customers of such utilities would otherwise be dropped or where the receiving utility agrees to return like quantities of energy within 14 days.
4. Curtail electric energy consumption by customers on Interruptible contracts to a maximum of 132 hours of use at contract demand per week.
5. Purchase energy from neighboring systems to the extent practicable.
6. Purchase energy from industrial customers with generation facilities to the extent practicable.
7. Through the use of news media and direct consumer contact, appeal to all customers (retail as well as wholesale) to reduce their nonessential use of electric energy as much as possible, in any case by at least 25%.
8. Reduce voltage around the clock to the extent feasible.
9. The Company will advise customers of the nature of the mandatory program to be introduced in C below, through direct contact and mass media, and establish an effective means of answering specific customer inquiries concerning the impact of the mandatory program on electricity availability.

(Cont'd on Sheet No. 3-10)

CAPACITY AND ENERGY CONTROL PROGRAM(Cont'd)

III. ENERGY EMERGENCY CONTROL PROGRAM(Cont'd)

B. PROCEDURES (Cont'd)

C. To be initiated – in the order indicated below -- when system fuel supplies are decreased to 50% of target days' operation of coal-fired plants and a continued downward trend in coal stocks is anticipated: (T)

1. Discontinue emergency deliveries to neighboring utilities unless the receiving utility agrees to return like quantities of energy within seven days.

2. Request all customers, retail as well as wholesale, to reduce their nonessential use of electric energy by 100%.

3 Request, through mass communication media, curtailment by all other customers a minimum of 15% of their electric use. These uses include lighting, air-conditioning, heating, manufacturing processes, cooking, refrigeration, clothes washing and drying and any other loads that can be curtailed.

4. All customers will be advised of the mandatory program specified below in D.

D. To be initiated when system fuel supplies are decreased to 40% of target days' operation of coal-fired generation and a continued downward trend in coal stocks is anticipated: (T)

1. Implement procedures for curtailment of service to all customers to a minimum service level that is not greater than that required for protection of human life and safety, protection of physical plant facilities and employees' security. This step asks for curtailment of the maximum load possible without endangering life, safety and physical facilities. (T)

2. All customers will be advised of the mandatory program specified below in E.

E. To be initiated when system fuel supplies are decreased to 30% of target days' operation of coal-fired generation and a continued downward trend in coal stocks is anticipated: (T)

Implement procedures for interruption of selected distribution circuits on a rotational basis, while minimizing – to the extent practicable – interruption to facilities that are essential to the public health and safety. (T)

F. The Energy Emergency Control Program will be terminated when:

1. The AEP System's remaining days of operation of coal-fired generation is at least 40% of normal target days' operation, and
2. Coal deliveries have been resumed, and
3. There is reasonable assurance that the AEP System's coal stocks are being restored to adequate levels.

With regard to mandatory curtailments identified in Items C, D, and E above, the Company proposes to monitor compliance after the fact. A customer exceeding his electric allotment would be warned to curtail his usage or face, upon continuing noncompliance and upon one day's actual written notice, disconnection of electric service for the duration of the energy emergency.

STANDARD NOMINAL VOLTAGES

The voltage available to any individual customer shall depend upon the voltage of the Company's lines serving the area in which customer is provided service.

Electric service provided under the Company's rate schedules will be 60 hertz alternating current delivered from various load centers at nominal voltages and phases as available in a given location as follows:

SECONDARY DISTRIBUTION VOLTAGES

Residential Service

Single phase 120/240 volts three wire or 120/208 volts three wire on network system.

General Service - All Except Residential

Single-phase 120/240 volts three wire or 120/208 volts three wire on network system. Three-phase 120/208 volts four wire on network system, 120/240 volts four wire, 240 volts three wire, 480 volts three wire and 277/480 volts four wire.

PRIMARY DISTRIBUTION VOLTAGES

The Company's primary distribution voltage levels at load centers are 2,400; 4,160Y; 7,200; 12,470Y, 19,900 and 34,500 (T)

SUBTRANSMISSION LINE VOLTAGES

The Company's sub transmission voltage levels are 19,900; 34,500; 46,000; and 69,000.

TRANSMISSION LINE VOLTAGES

The Company's transmission voltage levels are 138,000; 161,000; 345,000; and 765,000.

KENTUCKY POWER COMPANY

Original Sheet No. 5-1
Canceling ______ Sheet No. 5-1

P.S.C. ELECTRIC NO. 8

FUEL ADJUSTMENT CLAUSE

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D. R.S.-T.O.D., S.G.S., M.G.S., M.G.S.-T.O.D., L.G.S., Q.P., C.I.P.-T.O.D., C.S.-I.R.P., M.W., O.L., and S.L.

RATE.

1. The fuel clause shall provide for periodic adjustment per kwh of sales equal to the difference between the fuel costs per kwh of sales in the base period and in the current period according to the following formula:

$$\text{Adjustment Factor} = \frac{F\,(m)}{S\,(m)} - \frac{F\,(b)}{S\,(b)}$$

Where F is the expense of fossil fuel in the base (b) and current (m) periods; and S is sales in the base (b) and current (m) periods, all as defined below:

2. F(b)/S(b) shall be so determined that on the effective date of the Commission's approval of the utility's application of the formula, the resultant adjustment will be equal to zero (0).

3. Fuel costs (F) shall be the most recent actual monthly cost of:

   a. Fossil fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of the fuel related substitute generation, plus

   b. The actual identifiable fossil and nuclear fuel costs (if not known--the month used to calculate fuel (F), shall be deemed to be the same as the actual unit cost of the Company generation in the month said calculations are made. When actual costs become known, the difference, if any, between fuel costs (F) as calculated using such actual unit costs and the fuel costs (F) used in that month shall be accounted for in the current month's calculation of fuel costs (F) associated with energy purchased for reasons other than identified in paragraph (c) below, but excluding the cost of fuel related to purchases to substitute the forced outages, plus

   c. The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the Company to substitute for its own higher cost energy; and less

   d. The cost of fossil fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

   e. All fuel costs shall be based on weighted average inventory costing.

4. Forced outages are all nonscheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacturer, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection or acts of the public enemy, then the utility may, upon proper showing, with the approval of the Commission, include the fuel costs of substitute energy in the adjustment. Until such approval is obtained, in making the calculations of fuel costs (F) in subsection (3)(a) and (b) above, the forced outage costs to be subtracted shall be no less than the fuel cost related to the lost generation.

(Cont'd on Sheet No. 5-2)

DATE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

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KENTUCKY POWER COMPANY

Original Sheet No. 5-2
Canceling ______ Sheet No. 5-2

P.S.C. ELECTRIC NO. 8

FUEL ADJUSTMENT CLAUSE (Cont'd)

5. Sales (S) shall be all kwh's sold, excluding intersystem sales. Where, for any reason billed system sales cannot be coordinated with the fuel costs for the billing period, sales may be equated to the sum of (i) generation, (ii) purchases, (iii) interchange in, less (iv) energy associated with pumped storage operations, less (v) intersystem sales referred to in subsection (3)(d) above, less (vi) total system loss. Utility used energy shall not be excluded in the determination of sales (S).

6. The cost of fossil fuel shall include no items other than the invoice price of fuel less any cash or other discounts. The invoice price of fuel includes the cost of the fuel itself and necessary charges for transportation of the fuel from the point of acquisition to the unloading point, as listed in Account 151 of FERC Uniform System of Accounts or Public Utilities and Licensees.

7. At the time the fuel clause is initially filed, the utility shall submit copies of each fossil fuel purchase contract not otherwise on file with the Commission and all other agreements, options or similar such documents, and all amendments and modifications thereof related to the procurement of fuel supply and purchased power. Incorporation by reference is permissible. Any changes in the documents, including price escalations, or any new agreements entered into after the initial submission, shall be submitted at the time they are entered into. Where fuel is purchased from utility-owned or controlled sources, or the contract contains a price escalation clause, those facts shall be noted and the utility shall explain and justify them in writing. Fuel charges, which are unreasonable, shall be disallowed and may result in the suspension of the fuel adjustment clause. The Commission on its own motion may investigate any aspect of fuel purchasing activities covered by this regulation.

8. Any tariff filing which contains a fuel clause shall conform that clause with this regulation within three (3) months of the effective date of this regulation. The tariff filing shall contain a description of the fuel clause with detailed cost support.

9 The monthly fuel adjustment shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

10. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS61.870 to 61.884.

11. At six (6) month intervals, the Commission will conduct public hearings on a utility's past fuel adjustments. The Commission will order a utility to charge off and amortize, by means of a temporary decrease of rates, any adjustment it finds unjustified due to improper calculation or application of the charges or improper fuel procurement practice.

12. Every two (2) years following the initial effective date of each utility fuel clause, the Commission in a public hearing will review and evaluate past operations of the clause, disallow improper expenses, and to the extent appropriate, reestablish the fuel clause charge in accordance with Subsection 2.

13. Resulting cost per kilowatt-hour in September 2004 to be used as the base cost in Standard Fuel Adjustment Clause is:

$$\frac{\text{Fuel September 2004}}{\text{Sales September 2004}} = \frac{\$\,8{,}703{,}098}{527{,}226{,}000} = \$0.01651/\text{KWH}$$

This, as used in the Fuel Adjustment Clause, is 1.651 cents per kilowatt-hour.

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KENTUCKY POWER COMPANY

Original Sheet No. 6-1
Canceling ________ Sheet No. 6-1

P.S.C. ELECTRIC NO. 8

TARIFF R.S.
(Residential Service)

AVAILABILITY OF SERVICE.

Available for full domestic electric service through 1 meter to individual residential customers including rural residential customers engaged principally in agricultural pursuits.

RATE. (Tariff Codes 015, 017, 022)

Service Charge	~~$4.25~~ *$5.50* per month	(I)
Energy Charge:		
First 500 KWH per month	~~5.498¢~~ *7.259¢* per KWH	(I)
All Over 500 KWH per month	~~4.766¢~~ *6.494¢* per KWH	(I)

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased by an Experimental Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1, 29-2 and 29-3 of the Tariff Schedule.

NET MERGER SAVINGS CREDIT.

Bills computed according to the rates set forth herein will be decreased by a Net Merger Savings Credit Factor per KWH calculated in compliance with the Net Merger Savings Credit contained in Sheet No. 23-1 of this Tariff Schedule.

STATE ISSUES SETTLEMENT (T)

Bills computed according to the rates set forth herein will be increased by a State Issues Settlement Factor per KWH calculated in compliance with the State Issues Settlement Tariff contained in Sheet No. 28-1 of this tariff schedule.

NET CONGESTION RECOVERY. (T)

Bills computed according to the rates set forth herein will be increased or decreased by a Net Congestion Recovery Factor per KWH calculated in compliance with the Net Congestion Recovery Tariff contained in Sheet No. 30-1 of this Tariff Schedule.

DELAYED PAYMENT CHARGE.

Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion will be made.

(Cont'd. On Sheet 6-2)

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TARIFF R.S. (Cont'd)
(Residential Service)

STORAGE WATER HEATING PROVISION.

This provision is withdrawn except for the present installations of current customers receiving service hereunder at premises served prior to April 1, 1997.

If the customer installs a Company approved storage water heating system which consumes electrical energy only during off-peak hours as specified by the Company and stores hot water for use during on-peak hours, the following shall apply:

Tariff Code
012 (a) For Minimum Capacity of 80 gallons, the last 300 KWH of use in any month shall be billed at ~~2.396¢~~ *2.701¢* per KWH. (I)
013 (b) For Minimum Capacity of 100 gallons, the last 400 KWH of use in any month shall be billed at ~~2.396¢~~ *2.701¢* per KWH. (I)
014 (c) For Minimum Capacity of 120 gallons or greater, the last 500 KWH of use in any month shall be billed at ~~2.396¢~~ *2.701¢* per KWH. (I)

These provisions, however, shall in no event apply to the first 200 KWH used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For purpose of this provision, the on-peak billing period is defined as 7:00A.M. to 9:00P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00PM to 7:00AM for all weekdays and all hours of Saturday and Sunday.

The Company reserves the right to inspect at all reasonable times the storage water heating system and devices which qualify the residence for service under the storage water heater provision, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds that in its sole judgment the availability conditions of this provision are being violated, it may discontinue billing the Customer under this provision and commence billing under the standard monthly rate. (T)

This provision is subject to the Service Charge, the Fuel Adjustment Clause, the System Sales Clause, the Demand-Side Management Clause, the Environmental Surcharge, the Net Merger Savings Credit, and the State Issues Stipulation Charge factors as stated in the above monthly rate. (T)

LOAD MANAGEMENT WATER-HEATING PROVISION. (Tariff Code 011)

For residential customers who install a Company-approved load management water-heating system which consumes electrical energy primarily during off-peak hours specified by the Company and stores hot water for use during on-peak hours, of minimum capacity of 80 gallons, the last 250 KWH of use in any month shall be billed at ~~2.396¢~~ *2.701¢* per KWH. (I)

This provision, however, shall in no event apply to the first 200 KWH used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For the purpose of this provision, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

The Company reserves the right to inspect at all reasonable times the load management water-heating system(s) and devices which qualify the residence for service under the Load Management Water-Heating Provision. If the Company finds that, in its sole judgment, the availability conditions of this provision are being violated, it may discontinue billing the Customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the Service Charge, the Fuel Adjustment Clause, the System Sales Clause, the Demand-Side Management Clause, the Environmental Surcharge, the Net Merger Savings Credit, and the State Issues Stipulation Charge factors as stated in the above monthly rate. (T)

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

This service is available to rural domestic customers engaged principally in agricultural pursuits where service is taken through one meter for residential purposes as well as for the usual farm uses outside the home, but it is not extended to operations of a commercial nature or operations such as processing, preparing or distributing products not raised or produced on the farm, unless such operation is incidental to the usual residential and farm uses.

(Cont'd. On Sheet 6-3)

TARIFF R.S.(Cont'd)
(Residential Service)

SPECIAL TERMS AND CONDITIONS. (Cont'd)

This tariff is available for single-phase service only. Where 3-phase power service is required and/or where motors or heating equipment are used for commercial or industrial purposes, another applicable tariff will apply to such service.

The Company shall have the option of reading meters monthly or bimonthly and rendering bills accordingly. When bills are rendered bimonthly, the minimum charge and the quantity of KWH in each block of the rates shall be multiplied by two.

Pursuant to 807 KAR 5:041, Section 11, paragraph (5), of Public Service Commission Regulations, the Company will make an extension of ~~2500~~ *1,000* feet or less to its existing distribution line without charge for a prospective permanent residential customer served under this R.S. Tariff. (T)

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement.

KENTUCKY POWER COMPANY

Original Sheet No. 6-4
Canceling _______ Sheet No. 6-4

P.S.C. ELECTRIC NO. 8

TARIFF R.S. - L.M. - T.O.D.
(Residential Service Load Management Time-of-Day)

AVAILABILITY OF SERVICE.

Available to customers eligible for Tariff R.S. (Residential Service) who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours.

Households eligible to be served under this tariff shall be metered through one single-phase multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods.

RATE. (Tariff Codes 028, 029, 030, 031, 032, 033, 034, 035)

Service Charge.. $ ~~6.75~~ *$8.00* per month (I)
Energy Charge:
All KWH used during on-peak billing period............................ ~~7.830¢~~ *11.764¢* per KWH (I)
All KWH used during off-peak billing period............................ ~~2.396¢~~ *2.701¢* per KWH (I)

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

CONSERVATION AND LOAD MANAGEMENT CREDIT.

For the combination of an approved electric thermal storage space heating system and water heater, both of which are designed to consume electrical energy only between the hours of 9:00P.M. and 7:00A.M. for all days of the week, each residence will be credited 0.745¢ per KWH for all energy used during the off-peak billing period, for a total of 60 monthly billing periods following the installation and use of these devices in such residence.

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1, 29-2 and 29-3 of this Tariff Schedule.

(Cont'd On Sheet No. 6-5)

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TARIFF R.S.-L.M.-T.O.D. (Cont'd)
(Residential Service Load Management Time-of-Day)

NET MERGER SAVINGS CREDIT.

Bills computed according to the rates set forth herein will be decreased by a Net Merger Savings Credit Factor per KWH calculated in compliance with the Net Merger Savings Credit contained in Sheet No. 23-1 of this Tariff Schedule.

STATE ISSUES SETTLEMENT (T)

Bills computed according to the rates set forth herein will be increased by a State Issues Settlement Factor per KWH calculated in compliance with the State Issues Settlement Tariff contained in Sheet No. 28-1 of this tariff schedule.

NET CONGESTION RECOVERY. (T)

Bills computed according to the rates set forth herein will be increased or decreased by a Net Congestion Recovery Factor per KWH calculated in compliance with the Net Congestion Recovery Tariff contained in Sheet No. 30-1 of this Tariff Schedule.

DELAYED PAYMENT CHARGE.

Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion will be made.

SEPARATE METERING PROVISION.

Customers who use electric thermal storage space heating and water heaters which consume energy only during off-peak hours specified by the Company, or other automatically controlled load management devices such as space and/or water heating equipment that use energy only during off-peak hours specified by the Company, shall have the option of having these approved load management devices separately metered. The service charge for the separate meter shall be $3.00 per month.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

The Company reserves the right to inspect at all reasonable times the energy storage and load management devices which qualify the residence for service and for conservation and load management credits under this tariff, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds, that in its sole judgment, the availability conditions of this tariff are being violated, it may discontinue billing the Customer under this tariff and commence billing under the appropriate Residential Service Tariff.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

KENTUCKY POWER COMPANY

Original Sheet No. 6-6
CANCELING ______Sheet No. 6-6

PSC ELECTRIC NO. 8

TARIFF R.S. - T.O.D.
(Residential Service Time-of-Day)

AVAILABILITY OF SERVICE.

Available for residential electric service through one single-phase multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods to individual residential customers, including residential customers engaged principally in agricultural pursuits. Availability is limited to the first 1,000 customers applying for service under this tariff.

RATE. (Tariff Codes 036 and 037)

Service Charge...$ ~~6.75~~ *8.00* per month (I)
Energy Charge:
All KWH used during on-peak billing period............................ ~~7.830~~ *11.764¢* per KWH (I)
All KWH used during off-peak billing period........................ ~~2.396¢~~ *2.701¢* per KWH (I)

For the purpose of this tariff, the on-peak billing period is defined as 7:00A.M. to 9:00P.M. for all weekdays, Monday through Friday. The off-peak period is defined as 9:00P.M. to 7:00A.M. for all weekdays and all hours of Saturday and Sunday.

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bill computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1, 29-2 and 29-3 of this Tariff Schedule.

NET MERGER SAVINGS CREDIT.

Bills computed according to the rates set forth herein will be decreased by a Net Merger Savings Credit Factor per KWH calculated in compliance with the Net Merger Savings Credit contained in Sheet No. 23-1 of this Tariff Schedule.

STATE ISSUES SETTLEMENT (T)

Bills computed according to the rates set forth herein will be increased by a State Issues Settlement Factor per KWH calculated in compliance with the State Issues Settlement Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

NET CONGESTION RECOVERY. (T)

Bills computed according to the rates set forth herein will be increased or decreased by a Net Congestion Recovery Factor per KWH calculated in compliance with the Net Congestion Recovery Tariff contained in Sheet No. 30-1 of this Tariff Schedule.

DELAYED PAYMENT CHARGE.

Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion will be made.

(Cont'd on Sheet No. 6-7)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an order of the Public Service Commission in Case No.2005- dated

TARIFF R.S. - T.O.D. (Cont'd)
(Residential Service Time-of-Day)

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

KENTUCKY POWER COMPANY

Original Sheet No. 7-1
Canceling ______ Sheet No. 7-1

PSC ELECTRIC NO. 8

TARIFF S.G.S.
(Small General Service)

AVAILABILITY OF SERVICE.

Available for general service to customers with average monthly demands less than 10 KW and maximum monthly demands of less than 15 KW (excluding the demand served by the Load Management Time-of-Day provisions). (T)

RATE. (Tariff Code 211, 212)

Service Charge.. ~~$ 9.85~~ *$11.50* per month (I)
Energy Charge:
First 500 KWH per month.......................... ~~6.758¢~~ *8.761¢* per KWH (I)
All Over 500 KWH per month...................... ~~4.114¢~~ *4.984¢* per KWH (I)

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rate set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1, 29-2 and 29-3 of this Tariff Schedule.

NET MERGER SAVINGS CREDIT.

Bills computed according to the rates set forth herein will be decreased by a Net Merger Savings Credit Factor per KWH calculated in compliance with the Net Merger Savings Credit contained in Sheet No. 23-1 of this Tariff Schedule.

STATE ISSUES SETTLEMENT (T)

Bills computed according to the rates set forth herein will be increased by a State Issues Settlement Factor per KWH calculated in compliance with the State Issues Settlement Tariff contained in Sheet No. 28-1 of this tariff schedule.

NET CONGESTION RECOVERY. (T)

Bills computed according to the rates set forth herein will be increased or decreased by a Net Congestion Recovery Factor per KWH calculated in compliance with the Net Congestion Recovery Tariff contained in Sheet No. 30-1 of this Tariff Schedule.

DELAYED PAYMENT CHARGE.

This tariff is net if account is paid in full within 15 days of date of bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

(Cont'd. On Sheet 7-2)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2005- dated

TARIFF S.G.S. (Cont'd.)
(Small General Service)

LOAD MANAGEMENT TIME-OF-DAY PROVISION.

Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provision of this tariff.

RATE. (Tariff Code 225, 226)

Service Charge...$15.10 per month
Energy Charge:
All KWH used during on-peak billing period............................ ~~9.533¢~~ *12.295¢* per KWH (I)
All KWH used during off-peak billing period .... ~~2.505¢~~ *2.701¢* per KWH (I)

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

TERM OF CONTRACT.

The Company shall have the right to require contracts for periods of one year or longer.

OPTIONAL UNMETERED SERVICE PROVISION.

Available to customers who qualify for Tariff SGS and use the Company's service for commercial purposes consisting of small fixed electric loads such as traffic signals and signboards which can be served by a standard service drop from the Company's existing secondary distribution system. This service will be furnished at the option of the Company.

Each separate service delivery point shall be considered a contract location and shall be separately billed under the service contract. In the event one Customer has several accounts for like service, the Company may meter one account to determine the appropriate kilowatt-hour usage applicable for each of the accounts.

The Customer shall furnish switching equipment satisfactory to the Company. The Customer shall notify the Company in advance of every change in connected load, and the Company reserves the right to inspect the customer's equipment at any time to verify the actual load. In the event of the customer's failure to notify the Company of an increase in load, the Company reserves the right to refuse to serve the contract location thereafter under this provision, and shall be entitled to bill the customer retroactively on the basis of the increased load for the full period such load was connected or the earliest date allowed by Kentucky statute whichever is applicable.

Calculated energy use per month shall be equal to the contract capacity specified at the contract location times the number of days in the billing period times the specified hours of operation. Such calculated energy shall then be billed at the following rates:

RATE. (Tariff Code 204 (Mtrd), 213 (Umr))

Customer Charge...$ ~~7.00~~ *$7.50* per month (I)
Energy Charge:
First 500 KWH per month... ~~6.758¢~~ *8.761¢* per KWH (I)
All Over 500 KWH per month.. ~~4.114¢~~ *4.984¢* per KWH (I)

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

Customer with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

KENTUCKY POWER COMPANY

Original Sheet No. 8-1
Canceling ________ Sheet No. 8-1

P.S.C. ELECTRIC NO. 8

TARIFF M.G.S.
(Medium General Service)

AVAILABILITY OF SERVICE.

Available for general service to customers with average monthly demands greater than 10 KW or maximum monthly demands greater than 15 KW, but not more than 100 KW (excluding the demand served by the Load Management Time-of-Day provision). (T)

Existing customers not meeting the above criteria will be permitted to continue service under present conditions only for continuous service at the premises occupied on or prior to December 5, 1984.

RATE.

	Service Voltage			
	Secondary	Primary	Subtransmission	
Tariff Code	215, 216, 218	217, 220	236	
Service Charge per Month	~~$ 10.80~~ *$13.50*	~~$16.20~~ *$21.00*	~~$119.00~~ *$153.00*	(I)
Demand Charge per KW	$ ~~1.16~~ *$1.38*	$ ~~1.16~~ *$1.34*	$ ~~1.16~~ *$1.32*	(I)
Energy Charge:				
KWH equal to 200 times KW of monthly billing demand	~~5.736¢~~ *6.951¢*	~~5.179¢~~ *6.284¢*	~~4.703¢~~ *5.714¢*	(I)
KWH in excess of 200 times KW of monthly billing demand	~~4.768¢~~ *5.792¢*	~~4.521¢~~ *5.496¢*	~~4.351¢~~ *5.292¢*	(I)

RECREATIONAL LIGHTING SERVICE PROVISION.

Available for service to customers with demands of 5 KW or greater and who own and maintain outdoor lighting facilities and associated equipment utilized at baseball diamonds, football stadiums, parks and other similar recreational areas. This service is available only during the hours between sunset and sunrise. Daytime use of energy under this rate is strictly forbidden except for the sole purpose of testing and maintaining the lighting system. All Terms and Conditions of Service applicable to Tariff M.G.S. customers will also apply to recreational customers except for the Availability of Service.

RATE. (Tariff Code 214)

Service Charge .... ~~$10.80~~ *$13.50* per month (I)
Energy Charge .... ~~5.754¢~~ *6.520¢* per KWH (I)

MINIMUM CHARGE.

This tariff is subject to a minimum charge equal to the sum of the service charge plus the demand charge multiplied by 6 KW for the demand portion (6 KW and above) of the rate. (T)

The minimum monthly charge for industrial and coal mining customers contracting for 3-phase service after October 1, 1959 shall be ~~$4.82~~ *$5.75* per KW of monthly billing demand, subject to adjustment as determined under the fuel adjustment clause, system sales clause, demand-side management clause, the environmental surcharge, the net merger savings credit, the state issues stipulation charges, plus the service charge. (I)

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

(Cont'd. On Sheet No. 8-2)

DATE OF ISSUE September 26, 2005 DATE OF EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E.K. WAGNER DIRECTOR REGULATORY AFFAIRS FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2005- dated

TARIFF M.G.S. (Cont'd.)
(Medium General Service)

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1, 29-2 and 29-3 of this Tariff Schedule.

NET MERGER SAVINGS CREDIT.

Bills computed according to the rates set forth herein will be decreased by a Net Merger Savings Credit Factor per KWH calculated in compliance with the Net Merger Savings Credit contained in Sheet No. 23-1 of this Tariff Schedule.

STATE ISSUES STIPULATION CHARGE. (T)

Bills computed according to the rate set forth herein will be increased by a State Issues Stipulation Factor per KWH calculated in compliance with the State Issues Stipulation Tariff contained in Sheet No. 28-1.

NET CONGESTION RECOVERY. (T)

Bills computed according to the rates set forth herein will be increased or decreased by a Net Congestion Recovery Factor per KWH calculated in compliance with the Net Congestion Recovery Tariff contained in Sheet No. 30-1 of this Tariff Schedule.

DELAYED PAYMENT CHARGE.

This tariff is net if account is paid in full within 15 days of date of bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurements of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

(1) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.

(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

MONTHLY BILLING DEMAND.

Energy supplied hereunder will be delivered through not more than one single phase and/or polyphase meter. Customer's demand will be taken monthly to be the highest registration of a 15-minute integrating demand meter or indicator, or the highest registration of a thermal type demand meter. The minimum monthly billing demand shall not be less than (a) the minimum billing demand of 6 KW, or (b) 60% of the greater of (1) the customer's contract capacity in excess of 100 KW or (2) the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 KW.

LOAD MANAGEMENT TIME-OF-DAY PROVISION. (Tariff Codes 223, 224)

Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provision of this tariff.

(Cont'd. On Sheet 8-3)

TARIFF M.G.S (Cont'd)
(Medium General Service)

RATE.

Service Charge .... $ 3.00 per month
Energy Charge:
All KWH used during on-peak billing period .... ~~8.606¢~~ *11.388¢* per KWH (I)

All KWH used during off-peak billing period .... ~~3.059¢~~ *2.793¢* per KWH (D)

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

TERM OF CONTRACT.

Contracts under this tariff will be required of customers with normal maximum demands of ~~100~~ 500 KW or greater. Contracts under this tariff will be made for an initial period of not less than I year and shall remain in effect thereafter until either party shall give at least 6 months' written notice to the other of the intention to terminate the contract. The Company will have the right to make contracts for period s of longer than 1 year and to require contracts for Customers with normal maximum demands of less than ~~100~~ 500 KW. (T)

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to Customers having other source of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the Customer shall contract for the maximum demand in KW which the Company might be required to furnish, but no less than 10 KW. The Company shall not be obligated to supply demands in excess of that contracted for. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the Customer purchases power at a single point of both their power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

KENTUCKY POWER COMPANY

Original Sheet No. 8-4
Canceling _______ Sheet No. 8-4

P.S.C. ELECTRIC NO. 8

TARIFF M.G.S.-T.O.D.
(Medium General Service Time-of-Day)

AVAILABILITY OF SERVICE.

Available for general service to customers with normal maximum demands greater than 10 KW but not more than 100 KW. Availability is limited to the first 500 customers applying for service under this tariff.

RATE. (Tariff Code 229, 230)

Service Charge .... $ ~~11.60~~ *$14.30* per month (I)
Energy Charge:
All KWH used during on-peak billing period .... ~~8.606¢~~ *11.388¢* per KWH (I)

All KWH used during off-peak billing period .... ~~3.059¢~~ *2.793¢* per KWH (D)

For the purpose of this tariff, the on-peak billing period is defined as 7:00A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1, 29-2 and 29-3 of this Tariff Schedule.

NET MERGER SAVINGS CREDIT.

Bills computed according to the rates set forth herein will be decreased by a Net Merger Savings Credit Factor per KWH calculated in compliance with the Net Merger Savings Credit contained in Sheet No. 23-1 of this Tariff Schedule.

STATE ISSUES SETTLEMENT. (T)

Bills computed according to the rates set forth herein will be increased by a State Issues Settlement Factor per KWH calculated in compliance with the State Issues Settlement Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

NET CONGESTION RECOVERY. (T)

Bills computed according to the rates set forth herein will be increased or decreased by a Net Congestion Recovery Factor per KWH calculated in compliance with the Net Congestion Recovery Tariff contained in Sheet No. 30-1 of this Tariff Schedule.

(Cont'd on Sheet 8-5)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E. K. WAGNER (NAME) DIRECTOR OF REGULATORY SERVICES (TITLE) FRANKFORT KENTUCKY (ADDRESS)

Issued by authority of an Order of the Public Service Commission in Case No. 2005- dated

TARIFF M.G.S.-T.O.D. (Cont'd)
(Medium General Service Time-of-Day)

DELAYED PAYMENT CHARGE.

This tariff is net if account is paid in full within 15 days of date of bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service

Customers with PURPA Section 210 qualifying cogeneration and/or small power productions facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

KENTUCKY POWER COMPANY

Original Sheet No. 9-1
Canceling ______ Sheet No. 9-1

PSC ELECTRIC NO. 8

TARIFF L.G.S.
(Large General Service)

AVAILABILITY OF SERVICE.

Available for general service to customers with normal maximum demands greater than 100 KW but not more than 1,000 KW (excluding the demand served by the Load Management Time-of-Day provision).

Existing customers not meeting the above criteria will be permitted to continue service under present conditions only for continuous service at the premises occupied on or prior to December 5, 1984.

RATE.

	Service Voltage				
	Secondary	Primary	Subtransmission	Transmission	
Tariff Code	240, 242	244, 246	248		
Service Charge per Month	$ 85.00	$127.50	$535.50	$535.50	
Demand Charge per KW	~~$ 2.97~~ *$3.54*	$ ~~2.97~~ *$3.44*	$ ~~2.97~~ *$3.37*	$3.32	(I)
Excess Reactive Charge per KVA	$ 2.97	$ 2.97	$ 2.97	$ 2.97	
Energy Charge per KWH	~~4.078¢~~ *5.107¢*	~~3.419¢~~ *4.379¢*	~~2.890¢~~ *3.272¢*	2.862¢	(I)

MINIMUM CHARGE.

Bills computed under the above rate are subject to a monthly minimum charge comprised of the sum of the service charge and the minimum demand charge. The minimum demand charge is the product of the demand charge per KW and the monthly billing demand. (T)

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1, 29-2 and 29-3 of this Tariff Schedule.

NET MERGER SAVINGS CREDIT.

Bills computed according to the rates set forth herein will be decreased by a Net Merger Savings Credit Factor per KWH calculated in compliance with the Net Merger Savings Credit contained in Sheet No. 23-1 of this Tariff Schedule.

STATE ISSUES SETTLEMENT (T)

Bills computed according to the rates set forth herein will be increased by a State Issues Settlement Factor per KWH calculated in compliance with the State Issues Settlement Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

NET CONGESTION RECOVERY. (T)

Bills computed according to the rates set forth herein will be increased or decreased by a Net Congestion Recovery Factor per KWH calculated in compliance with the Net Congestion Recovery Tariff contained in Sheet No. 30-1 of this Tariff Schedule.

(Cont'd. On Sheet No.9-2)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2005- dated

KENTUCKY POWER COMPANY

Original Sheet No. 9-2
Canceling ______ Sheet No. 9-2

PSC ELECTRIC NO. 8

TARIFF L.G.S. (Cont'd.)
(Large General Service)

DELAYED PAYMENT CHARGE.

This tariff is net if account is paid in full within 15 days of date of bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following: (T)

(1) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.

(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

MONTHLY BILLING DEMAND.

Billing demand in KW shall be taken each month as the highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator, or at the Company's option as the highest registration of a thermal type demand meter or indicator. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

DETERMINATION OF EXCESS KILOVOLT-AMPERE (KVA) DEMAND

The maximum KVA demand shall be determined by the use of a multiplier equal to the reciprocal of the average power factor recorded during the billing month, leading or lagging, applied to the metered demand. The excess KVA demand, if any, shall be the amount by which the maximum KVA demand established during the billing period exceeds 115% of the kilowatts of metered demand. (T)

LOAD MANAGEMENT TIME-OF-DAY PROVISION.

Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provision of this tariff.

RATE. (Tariff Code 251)

Service Charge .... $81.80 per month
Energy Charge:
All KWH used during on-peak billing period .... ~~7.226¢~~ *9.625¢* per KWH (I)
All KWH used during off-peak billing period .... ~~2.414¢~~ *2.767¢* per KWH (I)

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

(Cont'd. On Sheet No. 9-3)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2005- dated

TARIFF L.G.S. (Cont'd)
(Large General Service)

TERM OF CONTRACT.

Contracts under this tariff will be made for customers requiring a normal maximum monthly demand between 500 KW and 1,000 KW and be made for an initial period of not less than 1 year and shall remain in effect thereafter until either party shall give at least 6 months written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts or periods greater than 1 year. For customers with demands less than 500 KW, a contract may, at the Company's option, be required. (T)

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

CONTRACT CAPACITY.

The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount up to 1,000 KW. Contracts will be made in multiples of 25 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company. (T)

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 100 KW nor more than 1,000 KW. The Company shall not be obligated to supply demands in excess of the contract capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billings periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above. (T)

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

KENTUCKY POWER COMPANY

Original Sheet No. 10-1
Canceling ______ Sheet No. 10-1

P.S.C. ELECTRIC NO. 8

TARIFF Q.P.
(Quantity Power)

AVAILABILITY OF SERVICE.

Available for commercial and industrial customers with demands less than 7,500 KW. Customers shall contract for a definite amount of electrical capacity in kilowatts, which shall be sufficient to meet normal maximum requirements, but in no case shall the contract capacity be less than 1,000 KW.

RATE.

	Secondary	Primary	Service Voltage Subtransmission	Transmission	
Tariff Code		358	359	360	
Service Charge per month	$ 276.00	$ 276.00	$ 662.00	$1,353.00	
Demand Charge per KW					
Of monthly on-peak billing demand	$14.27	$ ~~9.29~~ *$12.44*	$ ~~8.51~~ *$9.59*	$ ~~7.88~~ *$8.13*	(I)
Of monthly off-peak excess billing demand	$5.00	$ ~~0.90~~ *$3.46*	$ ~~0.86~~ *$0.93*	$ ~~0.85~~ ~~$~~*0.80*	(I)
Energy Charge per KWH	2.162¢	~~1.726¢~~ *2.108¢*	~~1.677¢~~ *2.078¢*	~~1.661¢~~ *2.051¢*	(I)

Reactive Demand Charge for each kilovar of maximum leading or lagging reactive demand in excess of 50 percent of the KW of monthly metered demand ....$ ~~0.57~~ *$0.72*/KVAR (I)

MINIMUM CHARGE.

This tariff is subject to a minimum charge equal to the Service Charge plus the Demand Charge per KW multiplied by the billing demand.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos.
22-1 and 22-2 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Surcharge Adjustment based on a percent of revenue in compliance with the Surcharge contained in Sheet Nos. 29-1, 29-2 and 29-3 of this Tariff Schedule.

NET MERGER SAVINGS CREDIT.

Bills computed according to the rates set forth herein will be decreased by a Net Merger Savings Credit Factor per KWH calculated in compliance with the Net Merger Savings Credit contained in Sheet No. 23-1 of this Tariff Schedule.

STATE ISSUES SETTLEMENT. (T)

Bills computed according to the rates set forth herein will be increased by a State Issues Settlement Factor per KWH calculated in compliance with the State Issues Settlement Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

(Cont'd On Sheet No. 10-2)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2005- dated

TARIFF Q.P. (Cont'd.)
(Quantity Power)

NET CONGESTION RECOVERY. (T)

Bills computed according to the rates set forth herein will be increased or decreased by a Net Congestion Recovery Factor per KWH calculated in compliance with the Net Congestion Recovery Tariff contained in Sheet No. 30-1 of this Tariff Schedule.

DELAYED PAYMENT CHARGE.

This tariff is net if account is paid in full within 15 days of date of bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KVA values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following: (T)

(1) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.
(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

MONTHLY BILLING DEMAND.

The on-peak billing demand in KW shall be taken each month as the single highest 15-minute integrated peak in KW as registered during the month by a demand meter or indicator, or, at the Company's option, as the highest registration of a thermal type demand meter or indicator, but the monthly on-peak billing demand so established shall in no event be less than 60% of the greater of (a) the Customer's contract capacity set forth on the contract for electric service or (b) the customer's highest previously established monthly billing demand uring the past 11 months.

Off-peak excess billing demand in any month shall be the amount of KW by which the off-peak billing demand exceeds the on-peak billing demand for the month.

The reactive demand in KVARs shall be taken each month as the highest single 15-minute integrated peak in KVARs as registered during the month by a demand meter or indicator, or, at the Company's option, as the highest registration of a thermal type demand meter or indicator.

For the purpose of this provision, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M., Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

TERM OF CONTRACT.

Contracts under this tariff will be made for an initial period of not less than two years and shall remain in effect thereafter until either party shall give at least 12 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than two years.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

CONTRACT CAPACITY

The Customer shall set forth the amount of capacity contracted for ("the contract capacity") in an amount equal to or greater than 1,000 KW but less than 7,500 KW; in multiplies of 100KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company. (T)

(Cont'd on Sheet No. 10-3)

TARIFF Q.P. (Cont'd)
(Quantity Power)

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is available for resale service to mining and industrial Customer who furnish service to Customer-owned camps or villages where living quarters are rented to employees and where the Customer purchases power at a single point for both the power and camp requirements. (T)

This tariff is also available to Customer having other sources of energy supply, but who desire to purchase standby or back-up electric s service from the Company. Where such conditions exist the Customer shall contract for the maximum amount of demand in KW which the Company might be required to furnish, but not less than 1,000 KW nor more than 7,500 KW. The Company shall not be obligated to supply demands in excess of that contracted capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph ""Minimum Charge" above. (T)

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

Customer with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP II or by special agreement with the Company.

KENTUCKY POWER COMPANY

Original Sheet No. 11-1
Canceling _____ Sheet No. 11-1

P.S.C. ELECTRIC NO. 8

TARIFF C.I.P. - T.O.D.
(Commercial and Industrial Power - Time-of-Day)

AVAILABILITY OF SERVICE.

Available for commercial and industrial KWHs with normal maximum demands of 7,500 KW and above. KWHs shall contract for a definite amount of electrical capacity in kilowatts which shall be sufficient to meet normal maximum requirements, but in no case shall the capacity contracted for be less than 7,500 KW.

RATE.

	Service Voltage			
	Primary	Subtransmission	Transmission	
Tariff Code	370	371	372	
Service Charge per Month	$ 276.00	$ 662.00	$ 1,353.00	
Demand Charge per KW				
On-peak	$ ~~8.60~~ *$14.78*	$ ~~7.89~~ *$11.68*	$ ~~7.34~~ *$10.12*	(I)
Off-peak	$ ~~2.02~~ *$3.84*	$ ~~1.23~~ *$1.03*	~~$1.05~~ *$0.91*	(I)
Energy Charge per KWH	~~1.726¢~~ *$1.724¢*	~~1.677¢~~ *1.698¢*	~~1.661¢~~ *1.678¢*	(I)

Reactive Demand Charge for each kilovar of maximum leading or lagging reactive demand in excess of 50 percent of the KW of monthly metered demand .... $ ~~0.60~~ *$0.72*/KVAR (I)

For the purpose of this tariff, the on-peak billing period is defined as 7:00 AM to 9:00 PM for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays and all hours of Saturday and Sunday.

MINIMUM DEMAND CHARGE.

The minimum demand charge shall be equal to the minimum billing demand times the following minimum demand rates:

Primary	Subtransmission	Transmission
~~$9.89~~/KW *$15.84/KW*	$ ~~8.99~~/KW *$12.73/KW*	$ ~~8.32~~/KW *$11.14/KW*

(I)

The minimum demand shall be the greater of 60% of the contract capacity set forth on the contract for electric service or 60% of the highest billing demand, on-peak or off-peak, recorded during the previous eleven months. (T)

MINIMUM CHARGE.

This tariff is subject to a minimum charge equal to the Service Charge plus the Minimum Demand Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule, unless the KWH is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

(Cont'd. On Sheet No. 11-2)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E. K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2005- dated

TARIFF C.I.P. - T.O.D. (Cont'd.)
(Commercial and Industrial Power - Time-of-Day)

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1, 29-2 and 29-3 of this Tariff Schedule.

NET MERGER SAVINGS CREDIT.

Bills computed according to the rates set forth herein will be decreased by a Net Merger Savings Credit Factor per KWH calculated in compliance with the Net Merger Savings Credit contained in Sheet No. 23-1 of this Tariff Schedule.

STATE ISSUES SETTLEMENT. (T)

Bills computed according to the rates set forth herein will be increased by a State Issues Settlement Factor per KWH calculated in compliance with the State Issues Settlement Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

NET CONGESTION RECOVERY. (T)

Bills computed according to the rates set forth herein will be increased or decreased by a Net Congestion Recovery Factor per KWH calculated in compliance with the Net Congestion Recovery Tariff contained in Sheet No. 30-1 of this Tariff Schedule.

DELAYED PAYMENT CHARGE.

This tariff is net if account is paid in full within 15 days of date of bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KVA values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

(1) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.
(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

MONTHLY BILLING DEMAND.

The monthly on-peak and off-peak billing demands in KW shall be taken each month as the highest single 15-minute integrated peak in KW as registered by a demand meter during the on-peak and off-peak billing periods, respectively.

The reactive demand in KVARs shall be taken each month as the highest single 15-minute integrated peak in KVAR's as registered during the month by the demand meter or indicator, or, at the Company's option, as the highest registration of a thermal type demand meter or indicator.

(Cont'd on Sheet 11-3)

TARIFF C.I.P. – T.O.D. (Cont'd)
(Commercial and Industrial Power – Time-of-Day)

TERM OF CONTRACT.

Contracts under this tariff will be made for an initial period of not less than two years and shall remain in effect thereafter until either party shall give at least 12 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than two years.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

CONTRACT CAPACITY.

The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount equal to or greater than 7,500 KW, in multiples of 100KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company. (T)

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to customers having other sources of energy supply, but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the customer shall contract for the maximum amount of demand in KW which the Company might be required to furnish, but not less than 7,500 KW. The Company shall not be obligated to supply demands in excess of the contract for capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

A customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by customer. When the size of the customer's load necessitates the delivery of energy to the customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the customer's system irrespective of contrary provisions in Terms and Conditions of Service.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP II or by special agreement with the Company.

TARIFF C.S.-I.R.P.
(Contract Service - Interruptible Power)

AVAILABILITY OF SERVICE.

Available for service to customers operating at subtransmission voltage or higher who contract for service under one of the Company's interruptible service options. The Company reserves the right to limit the total contract capacity for all customers served under this Tariff to 60,000 kW.

Loads of new customers locating within the Company's service area or load expansions by existing customers may be offered interruptible service as part of an economic development incentive. Such interruptible service shall not be counted toward the limitation on total interruptible power contract capacity, as specified above, and will not result in a change to the limitation on total interruptible power contract capacity.

CONDITIONS OF SERVICE.

The Company will offer eligible customers the option to receive service from a menu of interruptible power options pursuant to a contract agreed to by the Company and the Customer.

Upon receipt of a request from the Customer for interruptible service, the Company will provide the Customer with a written offer containing the rates and related terms and conditions of service under which such service will be provided by the Company. If the parties reach an agreement based upon the offer provided to the Customer by the Company, such written contract will be filed with the Commission. The contract shall provide full disclosure of all rates, terms and conditions of service under this Tariff, and any and all agreements related thereto, subject to the designation of the terms and conditions of the contract as confidential, as set forth herein.

The Customer shall provide reasonable evidence to the Company that the Customer's electric service can be interrupted in accordance with the provisions of the written agreement including, but not limited to, the specific steps to be taken and equipment to be curtailed upon a request for interruption.

The Customer shall contract for capacity sufficient to meet normal maximum interruptible power requirements, but in no event will the interruptible amount contracted for be less than 5,000 kW at any delivery point.

RATE. (Tariff Code 321)

Charges for service under this Tariff will be set forth in the written agreement between the Company and the Customer and will reflect a difference from the firm service rates otherwise available to the Customer.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

(Cont'd. On Sheet No. 12-2)

KENTUCKY POWER COMPANY

Original Sheet No 12-2
Canceling ______ Sheet No. 12-2

P.S.C. ELECTRIC NO. 8

TARIFF C.S.-I.R.P.
(Contract Service - Interruptible Power) (Cont'd.)

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule, unless the Customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1, 29-2 and 29-3 of this Tariff Schedule.

NET MERGER SAVINGS CREDIT

Bills computed according to the rates set forth herein will be decreased by a Net Merger Savings Credit Factor per KWH calculated in compliance with the Net Merger Savings Credit contained in Sheet No. 23-1 of this Tariff Schedule.

STATES ISSUES STIPULATION CHARGE. (T)

Bills computed according to the rate set forth herein will be increased by a State Issues Stipulation Factor per kwh calculated in compliance with the State Issues stipulation Tariff contained in Sheet No. 28-1.

NET CONGESTION RECOVERY. (T)

Bills computed according to the rates set forth herein will be increased or decreased by a Net Congestion Recovery Factor per KWH calculated in compliance with the Net Congestion Recovery Tariff contained in Sheet No. 30-1 of this Tariff Schedule.

DELAYED PAYMENT CHARGE.

This tariff is net if account is paid in full within 15 days of date of bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

TERM OF CONTRACT

The length of the agreement and the terms and conditions of service will be stated in the agreement between the Company and the Customer.

CONFIDENTIALITY

All terms and conditions of any written contract under this Tariff shall be protected from disclosure as confidential, proprietary trade secrets, if either the Customer or the Company requests a Commission determination of confidentiality pursuant to 807KAR 5:001, Section 7 and the request is granted.

(Cont'd. On Sheet No. 12-3)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2005- dated

TARIFF C.S.-I.R.P.
(Contract Service - Interruptible Power) (Cont'd.)

SPECIAL TERMS AND CONDITIONS

Except as otherwise provided in the written agreement, this Tariff is subject to the Company's Terms and Conditions of Service.

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply, but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist, the Customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 5,000 KW.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP II or by special agreement with the Company.

KENTUCKY POWER COMPANY

Original Sheet No. 13-1
Canceling ______ Sheet No. 13-1

P.S.C. ELECTRIC NO. 8

TARIFF M.W.
(Municipal Waterworks)

AVAILABILITY OF SERVICE.

Available only to incorporated cities and towns and authorized water districts and to utility companies operating under the jurisdiction of Public Service Commission of Kentucky for the supply of electric energy to waterworks systems and sewage disposal systems served under this tariff on September 1, 1982, and only for continuous service at the premises occupied by the Customer on this date. If service hereunder is discontinued, it shall not again be available.

Customer shall contract with the Company for a reservation in capacity in kilovolt-amperes sufficient to meet with the maximum load, which the Company may be required to furnish.

RATE. (Tariff Code 540)

Service Charge .... $22.90 per month
Energy Charge:
All KWH Used Per Month .... ~~4.658¢~~ *5.677¢* per KWH (I)

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the sum of the service charge plus ~~$3.05~~ *$3.65* per KVA as determined from customer's total connected load. The minimum monthly charge shall be subject to adjustments as determined under the Fuel Adjustment Clause. (I)

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-2 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1, 29-2 and 29-3 of this Tariff Schedule.

NET MERGER SAVINGS CREDIT.

Bills computed according to the rates set forth herein will be decreased by a Net Merger Savings Credit Factor per KWH calculated in compliance with the Net Merger Savings Credit contained in Sheet No. 23-1 of this Tariff Schedule.

STATE ISSUES SETTLEMENT (T)

Bills computed according to the rates set forth herein will be increased by a State Issues Settlement Factor per KWH calculated in compliance with the State Issues Settlement Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

NET CONGESTION RECOVERY. (T)

Bills computed according to the rates set forth herein will be increased or decreased by a Net Congestion Recovery Factor per KWH calculated in compliance with the Net Congestion Recovery Tariff contained in Sheet No. 30-1 of this Tariff Schedule.

(Cont'd On Sheet No. 13-2)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2005- dated

TARIFF M.W. (Cont'd)
(Municipal Waterworks)

PAYMENT.

Bills will be rendered monthly and will be due and payable on or before the 15th day from the date bills are mailed.

TERM OF CONTRACT.

Contracts under this tariff will be made for not less than 1 year with self-renewal provisions for successive periods of 1 year each until either party shall give at least 60 days' written notice to the other of the intention to discontinue at the end of any yearly period. The Company will have the right to require contracts for periods of longer than 1 year.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is not available to customers having other sources of energy supply.

KENTUCKY POWER COMPANY

Original Sheet No. 14-1
Canceling ______ Sheet No. 14-1

P.S.C. ELECTRIC NO. 8

TARIFF O.L.
(Outdoor Lighting)

AVAILABILITY OF SERVICE.

Available for outdoor lighting to individual customers in locations where municipal street lighting is not applicable.

RATE.

A. OVERHEAD LIGHTING SERVICE

Tariff Code				
	1.	High Pressure Sodium		
094		100 watts (9,500 Lumens)	$ ~~5.22~~ *$7.60* per lamp	(I)
113		150 watts (16,000 Lumens)	$ ~~6.18~~ *$8.40* per lamp	(I)
097		200 watts (22,000 Lumens)	$ ~~7.89~~ *$10.10* per lamp	(I)
098		400 watts (50,000 Lumens)	$ ~~12.75~~ *$15.35* per lamp	(I)
	2.	Mercury Vapor		
093*		175 watts (7,000 Lumens)	$ ~~5.36~~ *$8.40* per lamp	(I)
095*		400 watts (20,000 Lumens)	$ ~~8.95~~ *$14.00* per lamp	(I)

Company will provide lamp, photo-electric relay control equipment, luminaries and upsweep arm not over six feet in length, and will mount same on an existing pole carrying secondary circuits.

B. POST-TOP LIGHTING SERVICE

Tariff Code				
	1.	High Pressure Sodium		
111		100 watts (9,500 Lumens)	$ ~~8.99~~ *$10.80* per lamp	(I)
122		150 Watts (16,000 Lumens)	$ ~~14.69~~ *$17.65* per lamp	(I)
	2.	Mercury Vapor		
099*		175 watts (7,000 Lumens)	$ ~~6.24~~ *$9.75* per lamp	(I)

Company will provide lamp, photo-electric relay control equipment, luminaries, post, and installation including underground wiring for a distance of thirty feet from the Company's existing secondary circuits.

C. FLOOD LIGHTING SERVICE

Tariff Code				
	1.	High Pressure Sodium		
107		200 watts (22,000 Lumens)	$ ~~9.17~~ *$11.55* per lamp	(I)
109		400 watts (50,000 Lumens)	~~$12.61~~ *$15.30* per lamp	(I)
	2.	Metal Halide		
110		250 watts (20,500 Lumens)	~~$14.37~~ *$17.25* per lamp	(I)
116		400 watts (36,000 Lumens)	~~$18.81~~ *$22.60* per lamp	(I)
131		1000 watts (110,000 Lumens)	~~$40.37~~ *$48.55* per lamp	(I)

Company will provide lamp, photoelectric relay control equipment, luminaries, mounting bracket, and mount same on an existing pole carrying secondary circuits.

*These lamps are not available for new installations.

(Cont'd. on Sheet No. 14-2)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E.K. WAGNER (NAME) DIRECTOR OF REGULATORY SERVICES (TITLE) FRANKFORT, KENTUCKY (ADDRESS)

Issued by authority of an Order from the Public Service Commission in Case No. 2005- dated

KENTUCKY POWER COMPANY

Original Sheet No. 14-2
Canceling ______ Sheet No. 14-2

P.S.C. ELECTRIC NO. 8

TARIFF O.L. (Cont'd.)
(Outdoor Lighting)

RATE. (Cont'd.)

When new or additional facilities, other than those specified in Paragraphs A, B, and C, are to be installed by the Company, the customer in addition to the monthly charges, shall pay in advance the installation cost (labor and material) of such additional facilities extending from the nearest or most suitable pole of the Company to the point designated by the customer for the installation of said lamp, except that customer may, for the following facilities only, elect, in lieu of such payment of the installation cost to pay:

Wood pole...~~$1.80~~ *$2.30* per month (I)
Overhead wire span not over 150 feet...~~$1.00~~ *$1.30* per month (I)
Underground wire lateral not over 50 feet ....$5.35 per month
(Price includes pole riser and connections)

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule. The monthly kilowatt-hours for Fuel Adjustment Clause and the System Sales Clause computations are as follows:

	METAL HALIDE			MERCURY VAPOR		HIGH PRESSURE SODIUM			
	250 WATTS	400 WATTS	1000 WATTS	175 WATTS	400 WATTS	100 WATTS	150 WATTS	200 WATTS	400 WATTS
JAN	127	199	477	91	199	51	74	106	210
FEB	106	167	400	76	167	43	62	89	176
MAR	106	167	400	76	167	43	62	89	176
APR	90	142	340	65	142	36	53	76	150
MAY	81	127	304	58	127	32	47	68	134
JUNE	72	114	272	52	114	29	42	61	120
JULY	77	121	291	55	121	31	45	65	128
AUG	88	138	331	63	138	35	51	74	146
SEPT	96	152	363	69	152	39	57	81	160
OCT	113	178	427	81	178	45	66	95	188
NOV	119	188	449	86	188	48	70	100	198
DEC	129	203	486	92	203	52	75	108	214
TOTAL	1204	1896	4540	864	1896	484	704	1012	2000

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1, 29-2 and 29-3 of this Tariff Schedule.

NET MERGER SAVINGS CREDIT.

Bills computed according to the rates set forth herein will be decreased by a Net Merger Savings Credit Factor per KWH calculated in compliance with the Net Merger Savings Credit contained in Sheet No. 23-1 of this Tariff Schedule.

(Cont'd. On Sheet No. 14-3)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E. K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No.2005- dated

TARIFF O.L. (Cont'd.)
(Outdoor Lighting)

STATE ISSUES SETTLEMENT. (T)

Bills computed according to the rates set forth herein will be increased by a State Issues Settlement Factor per KWH calculated in compliance with the State Issues Settlement Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

NET CONGESTION RECOVERY. (T)

Bills computed according to the rates set forth herein will be increased or decreased by a Net Congestion Recovery Factor per KWH calculated in compliance with the Net Congestion Recovery Tariff contained in Sheet No. 30-1 of this Tariff Schedule.

DELAYED PAYMENT CHARGE.

A delayed payment charge on residential customer accounts will be applied pursuant to the delayed payment charge on Tariff R.S. On all accounts other than residential not paid in full within 15 days of date of bill an additional charge of 5% of the unpaid portion will be made.

HOURS OF LIGHTING.

All lamps shall burn from one-half hour after sunset until one-half hour before sunrise every night and all night, burning approximately 4,000 hours per annum.

OWNERSHIP OF FACILITIES.

All facilities necessary for service including fixtures, controls, poles, transformers, secondaries, lamps and other appurtenances shall be owned and maintained by the Company. All service and necessary maintenance will be performed only during the regular scheduled working hours of the Company.

The Company shall be allowed 3 working days after notification by the customer to replace all burned-out lamps.

TERM OF INITIAL SERVICE.

Term of initial service shall be required for an initial period of one year.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

The Company shall have the option of rendering monthly or bimonthly bills.

KENTUCKY POWER COMPANY

Original Sheet No. 15-1
Canceling ______ Sheet No. 15-1

P.S.C. ELECTRIC NO. 8

TARIFF S.L.
(Street Lighting)

AVAILABILITY OF SERVICE.

Available for lighting service for all the lighting of public streets, public highways and other public outdoor areas in municipalities, counties, and other governmental subdivisions where such service can be supplied from the existing general distribution systems.

RATE. (Tariff Code 528)

A. Overhead Service on Existing Distribution Poles

1. High Pressure Sodium

100 watts (9,500 lumens)..........$	~~4.56~~ *$5.60*	per lamp	(I)
150 watts (16,000 lumens)..........$	~~5.10~~ *$6.30*	per lamp	(I)
200 watts (22,000 lumens)..........$	~~5.93~~ *$7.80*	per lamp	(I)
400 watts (50,000 lumens)..........$	~~8.22~~ *$11.20*	per lamp	(I)

B. Service on New Wood Distribution Poles

1. High Pressure Sodium

100 watts (9,500 lumens)..........$	~~7.19~~ *$8.95*	per lamp	(I)
150 watts (16,000 lumens)..........$	~~7.85~~ *$9.70*	per lamp	(I)
200 watts (22,000 lumens)..........$	~~9.17~~ *$11.20*	per lamp	(I)
400 watts (50,000 lumens)..........$	~~11.47~~ *$14.55*	per lamp	(I)

C. Service on New Metal or Concrete Poles

1. High Pressure Sodium

100 watts (9,500 lumens)..........$	~~14.63~~ *$14.65*	per lamp	(I)
150 watts (16,000 lumens)..........$	15.20	per lamp	
200 watts (22,000 lumens)..........$	19.20	per lamp	
400 watts (50,000 lumens)..........$	~~20.02~~ *$20.00*	per lamp	(D)

Lumen rating is based on manufacturer's rated lumen output for new lamps.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule. The monthly kilowatt-hours for Fuel Adjustment Clause and the System Sales Clause computations are as follows:

(Cont'd. On Sheet No. 15-2)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2005- dated

KENTUCKY POWER COMPANY

Original Sheet No. 15-2
Canceling ______Sheet No. 15-2

P.S.C. ELECTRIC NO. 8

TARIFF S.L. (Cont'd.)
(Street Lighting)

FUEL ADJUSTMENT CLAUSE. (Cont'd.)

	HIGH PRESSURE SODIUM			
MONTH	100 WATTS	150 WATTS	200 WATTS	400 WATTS
JAN	51	74	106	210
FEB	43	62	89	176
MAR	43	62	89	176
APR	36	53	76	150
MAY	32	47	68	134
JUNE	29	42	61	120
JULY	31	45	65	128
AUG	35	51	74	146
SEPT	39	57	81	160
OCT	45	66	95	188
NOV	48	70	100	198
DEC	52	75	108	214
TOTAL	484	704	1012	2000

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1, 29-2 and 29-3 of this Tariff Schedule.

NET MERGER SAVINGS CREDIT.

Bills computed according to the rates set forth herein will be decreased by a Net Merger Savings Credit Factor per KWH calculated in compliance with the Net Merger Savings Credit contained in Sheet No. 23-1 of this Tariff Schedule.

STATE ISSUES STIPULATION CHARGE. (T)

Bills computed according to the rate set forth herein will be increased by a State Issues Stipulation Factor per KWH calculated in compliance with the State Issues Stipulation Tariff contained in Sheet No. 28-1.

NET CONGESTION RECOVERY. (T)

Bills computed according to the rates set forth herein will be increased or decreased by a Net Congestion Recovery Factor per KWH calculated in compliance with the Net Congestion Recovery Tariff contained in Sheet No. 30-1 of this Tariff Schedule.

SPECIAL FACILITIES.

When a customer requests street lighting service which requires special poles or fixtures, underground street lighting, or a line extension of more than one span of approximately 150 feet, the customer will be required to pay, in advance, an aid-to-construction in the amount of the installed cost of such special facilities.

(Cont'd On Sheet No. 15-3)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on an after October 27, 2005

ISSUED BY E. K. WAGNER (NAME) DIRECTOR OF REGULATORY SERVICES (TITLE) FRANKFORT, KENTUCKY (ADDRESS)

Issued by authority of an Order of the Public Service Commission in Case No.2005- dated

TARIFF S.L. (Cont'd.)
(Street Lighting)

PAYMENT.

Bills are due and payable within ten (10) days of the mailing date.

HOURS OF LIGHTING.

All lamps shall burn from one-half hour after sunset until one-half hour before sunrise every night and all night, burning approximately 4,000 hours per annum.

TERM OF CONTRACT.

Contracts under this tariff will ordinarily be made for an initial term of one year with self-renewal provisions for successive periods of one year each until either party shall give at least 60 days' notice to the other of the intention to discontinue at the end of the initial term or any yearly period. The Company may have the right to require contracts for periods of longer than one year if new or additional facilities are required.

TARIFF C. A. T. V.
(Cable Television Pole Attachment)

AVAILABILITY OF SERVICE.

Available to operators of cable television systems (Operators) furnishing cable television service in the operating area of Kentucky Power Company (Company) for attachments of aerial cables, wires and associated appliances (attachments) to certain distribution poles of Kentucky Power Company.

RATES.

Charge for attachments on a two-user pole .... $ ~~4.97~~ $*10.63* per pole/year (I)
Charge for attachments on a three-user pole .... $ ~~5.53~~ $ *6.59* per pole/year (I)

The above rate was calculated in accordance with the following formula:

Weighted Average Bare Pole Cost	x	Usage Factor	x	Carrying Charge		= Rate Per Pole

DELAYED PAYMENT CHARGE.

This Tariff is net if account is paid in full within 15 days of date of bill. On all accounts not so paid an additional charge of 5% of the unpaid balance will be made.

POLE SUBJECT TO ATTACHMENT.

When an Operator proposes to furnish cable television service within the Company's operating area and desires to make attachments on certain distribution poles of Company, Operator shall make written application, on a form furnished by Company, to install attachments specifying the location of each pole in question, the character of its proposed attachments and the amount and location of space desired, and any other information necessary to calculate the transverse and vertical load placed upon the pole as a result of the proposed attachment and any other facilities attached to the pole. Within twenty-one (21) days after receipt of the application, Company shall notify Operator whether and to what extent any special conditions will be required to permit the use by Operator of each such pole. Operator shall reimburse Company for any expenses incurred in reviewing such written applications for attachment. Operator shall have a non-exclusive right to use such poles of Company as may be used or reserved for use by Operator and any other poles of Company when brought hereunder in accordance with the procedure hereinafter provided. Company shall have the right to grant, by contract or otherwise to others rights or privileges to use any poles of the Company and Company shall have the right to continue and extend any such rights or privileges heretofore granted. All poles shall be and remain the property of Company regardless of any payment by Operator toward their cost and Operator shall, except for the rights provided hereunder, acquire no right, title or interest in or to any such pole.

STANDARDS FOR INSTALLATION.

All attachments and associated equipment of Operator (including without limitation, power supplies) shall be installed in a manner satisfactory to Company and so as not to interfere with the present or any future use which Company may desire to make of the poles covered by this Tariff. All such attachments and equipment shall be installed and at all times maintained by Operator so as to comply at least with the minimum requirements of the National Electrical Safety Code and any other applicable regulations or codes promulgated by state, local or other governmental authority having jurisdiction thereover. Power supply apparatus having as its largest dimension more than sixteen inches must be placed on a separate pole to be installed by Operator. Operator shall take necessary precautions by the installation of protective equipment or other means, to protect all persons and property of all kinds against injury or damage occurring by reason of Operator's attachments.

(Cont'd. On Sheet No. 16-2)

TARIFF C.A.T.V. (Cont'd.)
(Cable Television Pole Attachment)

POLE INSTALLATION OR REPLACEMENT; REARRANGEMENTS; GUYING.

In any case Operator proposes to install attachments on a pole to be erected by Company in a new location, and to provide adequate space or strength to accommodate such attachments (either at the request of Operator to comply with the aforesaid codes and regulations) such pole must, in Company's judgment, be taller and/or stronger than would be necessary to accommodate the facilities of Company and of other persons who have previously indicated that they desire to make attachments on such pole or with whom Company has an agreement providing for joint or share ownership of poles, the cost of such extra height and/or strength shall be paid to Company by Operator. Such cost shall be the difference between the cost in place of the new pole and the current cost in place of a pole considered by Company to be adequate for the facilities of Company and the attachments of such other persons.

Where in Company's judgment a new pole must be erected to replace an existing pole solely to adequately provide for Operator's proposed attachments, Operator agrees to pay Company for the entire cost of the new pole necessary to accommodate the existing facilities on the pole and Operator's proposed attachments, plus the cost of removal of the in-place pole, minus the salvage value, if any, of the removed pole. Title to the new pole shall remain with the Company. Operator shall also pay to Company and to any other owner of existing attachments on the pole the cost of removing each of their respective facilities or attachments from the existing pole and reestablishing the same or like facilities or attachments on the newly-installed pole.

If Operator's desired attachments can be accommodated on existing poles of Company by rearranging facilities of Company thereon of any other person, or if because of Operator's proposed attachments it is necessary for Company to rearrange its facilities on any pole not owned by it, then in any such case, Operator shall reimburse Company and any such other person for the respective expense incurred in making such rearrangement.

If because of the requirements of its business, Company proposed to replace an existing pole on which Operator has any attachment, or Company proposed to change the arrangements of its facilities on any such pole in such manner as to necessitate a rearrangement of Operator's attachment, or if as a result of any inspection of Operator's attachments Company determines that any such attachments are not in accordance with applicable codes or the provisions of this Tariff or are otherwise hazards Company shall give Operator not less than 48 hours notice of such proposed replacement or change, or any such violation or hazard, unless an emergency requires a shorter period. In such event, Operator shall at its expense relocate, rearrange or modify its attachments at the time specified by Company. If Operator fails to do so, or if any such emergency makes notice impractical, Company shall perform such relocation or rearrangement and Operator shall reimburse Company for the reasonable cost thereof.

Any additional guying or anchors required by reason of the attachments of Operator shall be provided at the expense of Operator and shall meet the requirements of all applicable codes or regulations and Company's generally applicable guying standards.

POLE INSPECTION.

Company reserves the right to inspect each new or proposed installation of Operator on Company's poles. In addition, Company may make periodic inspections, as conditions may warrant, for the purpose of determining compliance with the provisions of this Tariff. Company's right to make any inspections and any inspection made pursuant to such right shall not relieve Operator of any responsibility, obligation or liability assumed under this Tariff.

(Cont'd. On Sheet No. 16-3)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on or after October 27, 2005

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No.2005- dated

TARIFF C.A.T.V. (Cont'd.)
(Cable Television Pole Attachment)

UNAUTHORIZED ATTACHMENTS.

Operator shall make no attachment to or other use of any pole of Company or any facilities of Company thereon, except as authorized. Should such unauthorized attachment or use be made, Operator shall pay to the Company on demand two times the charges and fees, including but not limited to, any payable under the headings "RATES" and "POLE INSTALLATION OR REPLACEMENT; REARRANGEMENTS; GUYING" that would have been payable had such attachment been made on the date following the date of the last previous inspection required to be made by Company under applicable regulations of the Kentucky Public Service Commission.

ABANDONMENT BY OPERATOR.

Operator may at any time abandon the use of a pole hereunder by removing therefrom all of its attachments and by giving written notice thereof, on a form provided by the Company, and no pole shall be considered abandoned until such notice is received.

INDEMNITY.

Operator hereby agrees to indemnify, hold harmless, and defend Company from and against any and all loss, damage, cost or expense which Company may suffer or for which Company may be held liable because of interruption of Operator's service to its subscribers or because of interference with television reception of said subscribers or others, or by reason of bodily injury, including death, to any person, or damage to or destruction of any property, including loss of use thereof, arising out of or in any manner connected with the attachment, operation, and maintenance of the facilities of Operator on the poles of Company under this Tariff, when due to any act, omission or negligence of Operator, or to any such act, omission or negligence of Operator's respective representatives, employees, agents or contractors.

INSURANCE.

Operator agrees to obtain and maintain at all times policies of insurance as follows:

(a) Comprehensive bodily injury liability insurance in an amount not less than $1,000,000 for any one occurrence
(b) Comprehensive property damage liability insurance in an amount not less than $500,000 for any one occurrence.
(c) Contractual liability insurance in an amount not less than the foregoing minimums to cover the liability assumed by the Operator under the agreement or indemnity set forth above.

Prior to making attachments at Company's poles, Operator shall furnish to Company two copies of a certificate, from an insurance carrier licensed to do business in Kentucky, stating that policies of insurance have been issued by it to Operator providing for the insurance listed above and that such policies are in force. Such certificate shall state that the insurance carrier will give Company fifteen (15) days' prior written notice of any cancellation of or material change in such policies.

EASEMENTS.

Operator shall secure any right, license or permit from any governmental body, authority or other person or persons which may be required for the construction or maintenance of attachments of Operator. Company does not convey nor guarantee any easements, rights-of-way or franchises for the construction and maintenance of said attachments. Operator hereby agrees to indemnify and save harmless Company from any and all claims, including the expenses incurred by Company to defend itself against such claims, resulting from or arising out of the failure of Operator to secure such right, license, permit or easement for the construction or maintenance of said attachments on Company's poles.

(Cont'd. On Sheet 16-4)

TARIFF C.A.T.V. (Cont'd.)
(Cable Television Pole Attachment)

CHARGES AND FEES.

Operator agrees to pay Company in advance, semi-annually, charges to be computed as set forth in Tariff, and such other charges as may be provided for herein, for the use of each of Company's poles, any portion of which is occupied by, or reserved at Operator's request for the attachments of Operator.

Operator agrees to reimburse Company for all reasonable non-recurring expenses caused by or attributable to Operator's initial attachments including without limitation the amounts set forth herein before and the expenses of Company in examining poles used but not owned by Company to which Operator proposes to make attachments.

FEES FOR ADDITIONAL ATTACHMENTS OR REMOVALS.

For attachments made or removed which are reported to the Company between billing dates, Operator shall be billed or credited a prorated amount of the annual charge effective with the date of attachment or removal on the Operator's next bill.

ADVANCE BILLING

Payment of amounts due hereunder are due on the dates or at the times indicated with respect to each such payment. In the event the time for any payment is not specified, such payment shall be due fifteen (15) days from the date of the invoice therefore. In all amounts not so paid an addition charge of five percent (5%) will be assessed. Where the provisions of the Tariff require any payment by Operator to the Company other than for attachment charges, Company may, at its option, require that the estimated amount thereof be paid in advance of permission to use any pole or the performance by company of any work. In such a case, Company shall invoice any deficiency or refund any excess to Operator after the current amount of such payment has been determined.

DEFAULT OR NON-COMPLIANCE.

If Operator fails to comply with any of the provisions of this Tariff or defaults in the performance of any of its obligations under this Tariff and fails within thirty (30) days, after written notice from Company to correct such default or non-compliance, Company may, as its option forthwith take any one or more of the following actions: terminate the specific permit or permits covering the poles to which such default or non-compliance is applicable; remove, relocate or rearrange attachments of Operator to which such default or non-compliance relates, all at Operator's expense; decline to permit additional attachments hereunder until such default is cured; or in the event of any failure to pay any of the charges, fees or amounts provided in this Tariff or any other substantial default, or of repeated defaults terminate Operator's right of attachment. No liability shall be incurred by Company because of any or all such actions except for negligent destruction by the Company of CATV equipment in any relocation or removal of such equipment. The remedies provided herein are cumulative and in addition to any other remedies available to Company.

PRIOR AGREEMENTS.

This Tariff terminates and supersedes any previous agreement, license or joint use affecting Company's poles and Operator's attachments covered herein.

(Cont'd on Sheet No. 16-5)

TARIFF C. A. T. V. (Cont'd)
(Cable Television Pole Attachment)

ASSIGNMENT

This Tariff shall be binding upon and inure to the benefits of the parties hereto, their respective successors and/or assigns, but Operator shall not assign, transfer or sublet any of the rights hereby granted without the prior written consent of the Company, which shall not be unreasonably withheld, and any such purported assignment, transfer or subletting without such consent shall be void.

PERFORMANCE WAIVER.

Neither party shall be considered in default in the performance of its obligations herein, or any of them, to the extent that performance is delayed or prevented due to causes beyond the control of said party, including but not limited to, Acts of God or the public enemy, war, revolution, civil commotion, blockade or embargo, acts of government, any law, order, proclamation, regulation, ordinance, demand, or requirement of any government, fires, explosions, cyclones, floods, unavoidable casualties, quarantine, restrictions, strikes, labor disputes, lock-outs, and other causes beyond the reasonable control of either of the parties.

PRESERVATION OF REMEDIES.

No delay or omission in the exercise of any power or remedy herein provided or otherwise available to the Company shall impair or affect its right thereafter to exercise the same.

HEADINGS.

Headings used in this Tariff are inserted only for the convenience of the parties and shall not affect the interpretation or construction of this Tariff.

KENTUCKY POWER COMPANY

Original Sheet No. 17-1
Canceling ______ Sheet No. 17-1

P.S.C. ELECTRIC NO. 8

TARIFF COGEN/SPP I
(Cogeneration and/or Small Power Production--100 KW or Less)

AVAILABILITY OF SERVICE.

This tariff is available to customers with cogeneration and/or small power production (COGEN/SPP) facilities which qualify under Section 210 of the Public Utility Regulatory Policies Act of 1978, and which have a total design capacity of 100 KW or less. Such facilities shall be designed to operate properly in parallel with the Company's system without adversely affecting the operation of equipment and services of the Company and its customers, and without presenting safety hazards to the Company and customer personnel.

The customer has the following options under this tariff, which will affect the determination of energy and capacity and the monthly metering charges:

Option 1 -The customer does not sell any energy or capacity to the Company, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 2 - The customer sells to the Company the energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities in excess of the customer's total load, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 3 - The customer sells to the Company the total energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities, while simultaneously purchasing from the Company its total load requirements, as determined by appropriate meters located at one delivery point.

MONTHLY CHARGES FOR DELIVERY FROM THE COMPANY TO THE CUSTOMER.

Such charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the tariff appropriate for the customer, except that Option 1 and Option 2 customers with cogeneration and/or small power production facilities having a total design capacity of more than 10 KW shall be served under demand-metered tariffs, and except that the monthly billing demand under such tariffs shall be the highest determined for the current and previous two billing periods. The above three-month billing demand provision shall not apply under Option 3.

ADDITIONAL CHARGES.

There shall be additional charges to cover the cost of special metering, safety equipment and other local facilities installed by the Company due to COGEN/SPP facilities, as follows:

Monthly Metering Charge

The additional monthly charge for special metering facilities shall be as follows:

Option 1 - Where the customer does not sell electricity to the Company, a detent shall be used on the energy meter to prevent reverse rotation. The cost of such meter alteration shall be paid by the customer as part of the Local Facilities Charge.

Options 2 & 3 - Where meters are used to measure the excess or total energy and average on-peak capacity purchased by the Company:

	Single Phase	Polyphase	
Standard Measurement	~~$5.90~~ *$6.75*	~~$11.20~~ *$8.45*	(I)
T.O.D. Measurement	~~$15.00~~ *$7.55*	~~$20.25~~ *$8.85*	(D)

(Cont'd. On Sheet No. 17-2)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No.2005- dated

TARIFF COGEN/SPP I (Cont'd.)
(Cogeneration and/or Small Power Production—100 KW or Less)

ADDITIONAL CHARGES. (Cont'd.)

Monthly Metering Charge (Cont'd.)

Under Option 3, when metering voltage for COGEN/SPP facilities is the same as the Company's delivery voltage, the customer shall, at his option, either route the COGEN/SPP totalized output leads through the metering point, or make available at the metering point for the use of the Company and, as specified by the Company, metering current leads which will enable the Company to measure adequately the total electrical energy and average capacity produced by the qualifying COGEN/SPP facilities, as well as to measure the electrical energy consumption and capacity requirements of the customer's total load. When metering voltage for COGEN/SPP facilities is different from the Company's delivery voltage, metering requirements and charges shall be determined specifically for each use.

Local Facilities Charge

Additional charges to cover "interconnection costs" incurred by the Company shall be determined by the Company for each case and collected from the customer. For Options 2 and 3, the cost of metering facilities shall be covered by the Monthly Metering Charge and shall not be included in the Local Facilities Charge. The customer shall make a one-time payment for the Local Facilities Charge at the time of installation of the required additional facilities, or, at his option, up to 12 consecutive equal monthly payments reflecting an annual interest charge as determined by the Company, but not to exceed the cost of the Company's most recent issue of long-term debt. If the customer elects the installment payment option, the Company may require a reasonable security deposit.

MONTHLY CREDITS OR PAYMENTS FOR ENERGY AND CAPACITY DELIVERIES.

Energy Credit

The following credits or payments from the Company to the customer shall apply for the electrical energy delivered to the Company:

Standard Meter - All KWH .... ~~1.57~~ ¢/KWH *2.81¢* (I)

T.O.D. Meter
On-Peak KWH .... ~~1.72~~ ¢/ KWH *3.54¢* (I)
Off-Peak KWH .... ~~1.45~~ ¢/KWH *2.29¢* (I)

Capacity Credit

If the customer contracts to deliver or produce a specified excess or total average capacity during the monthly billing period (monthly contract capacity), or a specified excess or total average capacity during the on-peak monthly billing period (on-peak contract capacity), then the following capacity credits or payment from the Company to the customer shall apply:

If standard energy meters are used,

A. ~~$0.95/~~ *$0.78/* KW/month, times the lowest of: (I)

(1) monthly contract capacity, or

(2) current month metered average capacity, i.e., KWH delivered to the Company or produced by COGEN/SPP facilities divided by 730, or

(3) lowest average capacity metered during the previous two months if less than monthly contract capacity.

(Cont'd. On Sheet 17-3)

KENTUCKY POWER COMPANY

Original Sheet No. 17-3
Canceling ______ Sheet No. 17-3

P.S.C. ELECTRIC NO. 8

TARIFF COGEN/SPP I (Cont'd.)
(Cogeneration and/or Small Power Production--100 KW or Less)

MONTHLY CREDITS OR PAYMENTS FOR ENERGY AND CAPACITY DELIVERIES. (Cont'd.)

Capacity Credit (Cont'd.)

If T.O.D. energy meters are used,

B. ~~$2.10~~ *$1.87*/KW/month, times the lowest of: (D)

(1) on-peak contract capacity, or

(2) current month on-peak metered average capacity, i.e., on-peak KWH delivered to the Company or produced by COGEN/SPP facilities divided by 327, or

(3) lowest on-peak average capacity metered during the previous two months, if less than on-peak contract capacity.

The above energy and capacity credit rates are subject to revisions from time to time as approved by the Commission.

ON-PEAK AND OFF-PEAK PERIODS.

The on-peak period shall be defined as starting at 7:00A.M. and ending at 9:00 P.M., local time, Monday through Friday.

The off-peak period shall be defined as starting at 9:00 P.M. and ending at 7:00A.M., local time, Monday through Friday, and all hours of Saturday and Sunday.

CHARGES FOR CANCELLATION OR NON PERFORMANCE CONTRACT.

If the customer should, for a period in excess of six months, discontinue or substantially reduce for any reason the operation of cogeneration and/or small power production facilities which were the basis for the monthly contract capacity or the on-peak contract capacity, the customer shall be liable to the Company for an amount equal to the total difference between the actual payments for capacity paid to the customer and the payments for capacity that would have been paid to the customer pursuant to this Tariff COGEN/SPP I or any successor tariff. The Company shall be entitled to interest on such amount at the rate of the Company's most recent issue of long-term debt at the effective date of the contract.

TERM OF CONTRACT.

Contracts under this tariff shall be made for a period not less than one year.

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on an after October 27, 2005

ISSUED BY E. K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2005- dated

KENTUCKY POWER COMPANY

Original Sheet No. 18-1
Canceling _______ Sheet No. 18-1

P.S.C. ELECTRIC NO. 8

TARIFF COGEN/SPP II
(Cogeneration and/or Small Power Production--Over 100 KW)

AVAILABILITY OF SERVICE.

This tariff is available to customers with cogeneration and/or small power production (COGEN/SPP) facilities which qualify under Section 210 of the Public Utility Regulatory Policies Act of 1978, and which have a total design capacity of over 100 KW. Such facilities shall be designed to operate properly in parallel with the Company's system without adversely affecting the operation of equipment and services of the Company and its customers, and without presenting safety hazards to the Company and customer personnel.

The customer has the following options under this tariff, which will affect the determination of energy and capacity and the monthly metering charges:

Option 1 - The customer does not sell any energy or capacity to the Company, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 2 - The customer sells to the Company the energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities in excess of the customer's total load, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 3 - The customer sells to the Company the total energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities, while simultaneously purchasing from the Company its total load requirements, as determined by appropriate meters located at one delivery point.

MONTHLY CHARGES FOR DELIVERY FROM THE COMPANY TO THE CUSTOMER.

Such charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the tariff appropriate for the customer, except that Option 1 and Option 2 customers shall be served under demand-metered tariffs, and except that the monthly billing demand under such tariffs shall be the highest determined for the current and previous two billing periods. The above three-month billing demand provision shall not apply under Option 3.

ADDITIONAL CHARGES.

There shall be additional charges to cover the cost of special metering, safety equipment and other local facilities installed by the Company due to COGEN/SPP facilities, as follows:

Monthly Metering Charge

The additional monthly charge for special metering facilities shall be as follows:

Option 1 - Where the customer does not sell electricity to the Company, a detent shall be used on the energy meter to prevent reverse rotation. The cost of such meter alteration shall be paid by the customer as part of the Local Facilities Charge.

Options 2 & 3- Where meters are used to measure the excess or total energy and average on peak capacity purchased by the Company:

	Single Phase	Polyphase	
Standard Measurement	~~$5.90~~ *$6.75*	~~$11.20~~ *$8.45*	(I)
T.O.D. Measurement	~~$15.00~~ *$7.55*	~~$20.25~~ *$8.85*	(D)

(Cont'd. On Sheet No. 18-2)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

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KENTUCKY POWER COMPANY

Original Sheet No. 18-2
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P.S.C. ELECTRIC NO. 8

TARIFF COGEN/SPP II (Cont'd.)

(Cogeneration and/or Small Power Production--Over 100 KW)

ADDITIONAL CHARGES. (Cont'd.)

Monthly Metering Charge (Cont'd)

Under Option 3, when metering voltage for COGEN/SPP facilities is the same as the Company's delivery voltage, the customer shall, at his option, either route the COGEN/SPP totalized output leads through the metering point, or make available at the metering point for the use of the Company and, as specified by the Company, metering current leads which will enable the Company to measure adequately the total electrical energy and average capacity produced by the qualifying COGEN/SPP facilities, as well as to measure the electrical energy consumption and capacity requirements of the customer's total load. When metering voltage for COGEN/SPP facilities is different from the Company's delivery voltage, metering requirements and charges shall be determined specifically for each case.

Local Facilities Charge

Additional charges to cover "interconnection costs" incurred by the Company shall be determined by the Company for each case and collected from the customer. For Options 2 and 3, the cost of metering facilities shall be covered by the Monthly Metering Charge and shall not be included in the Local Facilities Charge. The customer shall make a one-time payment for the Local Facilities Charge at the time of installation of the required additional facilities, or, at his option, up to 12 consecutive equal monthly payments reflecting an annual interest charge as determined by the Company, but not to exceed the cost of the Company's most recent issue of long-term debt. If the customer elects the installment payment option, the Company may require a reasonable security deposit.

MONTHLY CREDITS OR PAYMENTS FOR ENERGY AND CAPACITY DELIVERIES.

Energy Credit

The following credits or payments from the Company to the customer shall apply for the electrical energy delivered to the Company:

Standard Meter - All KWH .... ~~1.57~~ ¢/KWH *$2.81* (I)

T.O.D. Meter
On-Peak KWH .... ~~1.72~~ ¢/KWH *3.54¢* (I)
Off-Peak KWH .... ~~1.45~~ ¢/KWH *2.29¢* (I)

(Cont'd. On Sheet 18-3)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No.2005- dated

TARIFF COGEN/SPP II (Cont'd.)
(Cogeneration and/or Small Power Production–Over 100 KW)

MONTHLY CREDITS OR PAYMENTS FOR ENERGY AND CAPACITY DELIVERIES. (Cont'd.)

Capacity Credit

If the customer contracts to deliver or produce a specified excess or total average capacity during the monthly billing period (monthly contract capacity), or a specified excess or total average capacity during the on-peak monthly billing period (on-peak contract capacity), then the following capacity credits or payment from the Company to the customer shall apply:

If standard energy meters are used,

A. ~~$0.95~~/ *$0.78*/KW/month, times the lowest of: (D)

(1) monthly contract capacity, or

(2) current month metered average capacity, i.e., KWH delivered to the Company or produced by COGEN/SPP facilities divided by 730, or

(3) lowest average capacity metered during the previous two months if less than monthly contract capacity.

If T.O.D. energy meters are used,

B. ~~$2.10~~ *$1.87*/KW/month, times the lowest of: (D)

(1) on-peak contract capacity, or

(2) current month on-peak metered average capacity, i.e., on-peak KWH delivered to the Company or produced by COGEN/SPP facilities divided by 327, or

(3) lowest on-peak average capacity metered during the previous two months, if less than on-peak contract capacity.

The above energy and capacity credit rates are subject to revisions from time to time as approved by the Commission.

ON-PEAK AND OFF-PEAK PERIODS.

The on-peak period shall be defined as starting at 7:00 A.M. and ending at 9:00 P.M., local time, Monday through Friday.

The off-peak period shall be defined as starting at 9:00 P.M. and ending at 7:00 A.M., local time, Monday through Friday, and all hours of Saturday and Sunday.

CHARGES FOR CANCELLATION OR NON PERFORMANCE CONTRACT.

If the customer should, for a period in excess of six months, discontinue or substantially reduce for any reason the operation of cogeneration and/or small power production facilities which were the basis for the monthly contract capacity or the on-peak contract capacity, the customer shall be liable to the Company for an amount equal to the total difference between the actual payments for capacity paid to the customer and the payments for capacity that would have been paid to the customer pursuant to this Tariff COGEN/SPP II or any successor tariff. The Company shall be entitled to interest on such amount at the rate of the Company's most recent issue of long-term debt at the effective date of the contract.

TERM OF CONTRACT.

Contracts under this tariff shall be made for a period not less than one year.

KENTUCKY POWER COMPANY

Original Sheet No. 19-1
Canceling ______ Sheet No. 19-1

P.S.C. ELECTRIC NO. 8

TARIFF S. S. C.
(System Sales Clause)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., S.G.S., M.G.S., M.G.S.-T.O.D., L.G.S., Q.P., C.I.P.-T.O.D., C.S.-I.R.P., M.W., O.L., and S.L.

RATE.

1. When the monthly net revenues from system sales are above or below the monthly base net revenues from system sales, as provided in paragraph 3 below, an additional credit or charge equal to the product of the KWHs and a system sales adjustment factor (A) shall be made, where "A", calculated to the nearest 0.0001 mill per kilowatt-hour, is defined as set forth below.

   System Sales Adjustment Factor (A) = (.5[Tm - Tb])/Sm

   In the above formula "T" is Kentucky Power Company's (KPCo) monthly net revenues from system sales in the current (m) and base (b) periods, and "S" is the Kwh sales in the current (m) period, all defined below.

2. The net revenue from American Electric Power (AEP) System deliveries to non-associated companies that are shared by AEP Member Companies, including KPCo, in proportion to their Member Load Ratio and as reported in the Federal Energy Regulatory Commission's Uniform System of Accounts under Account 447, Sales for Resale, shall consist of and be derived as follows:

3.
   a. KPCo's Member Load Ratio share of total revenues from system sales as recorded in Account 447, less b. and c. below.

   b. KPCo's Member Load Ratio share of total out-of-pocket costs incurred in supplying the power and energy for the deliveries in a. above.

      The out-of-pocket costs include all operating, maintenance, tax, transmission losses and other expenses that would not have been incurred if the power and energy had not been supplied for such deliveries, including demand and energy charges for power and energy supplied by Third Parties.

   c. KPCo's environmental costs allocated to non-associated utilities in the Company's Environmental Surcharge Report.

4. The base monthly net revenues from system sales are as follows:

Billing Month	Base Net Revenues from System Sales (Total Company Basis)	
January	$ ~~895,960~~ *$2,815,074*	(I)
February	~~767,802~~ *$2,365,178*	(I)
March	~~893,126~~ *$1,832,408*	(I)
April	~~1,036,738~~ *$2,862,969*	(I)
May	~~1,085,852~~ *$2,501,869*	(I)
June	~~1,324,166~~ *$3,280,306*	(I)
July	~~1,027,403~~ *$2,994,548*	(I)
August	~~1,154,184~~ *$1,902,637*	(I)
September	~~912,736~~ *$1,756,798*	(I)
October	~~731,014~~ *$1,122,316*	(I)
November	~~624,320~~ *$1,331,388*	(I)
December	~~862,035~~ *$2,142,114*	(I)

(Cont'd on Sheet No. 19-2)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E.K. WAGNER (NAME) DIRECTOR OF REGULATORY SERVICES (TITLE) FRANKFORT, KENTUCKY (ADDRESS)

Issued by authority of an Order of the Public Service Commission in Case No.2005- dated

KENTUCKY POWER COMPANY

Original Sheet No. 19-2
Canceling _____ Sheet No. 19-2

P.S.C. ELECTRIC NO. 8

TARIFF S. S. C. (Cont'd.)
(System Sales Clause)

4. Sales (S) shall be equated to the sum of (a) generation (including energy produced by generating plant during the construction period), (b) purchase, and (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) inter-system sales and less (f) total system losses.

5. The system sales adjustment factor shall be based upon estimated monthly revenues and costs for system sales, subject to subsequent adjustment upon final determination of actual revenues and costs.

6. The monthly System Sales Clause shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

7. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

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ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

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KENTUCKY POWER COMPANY

Original Sheet No. 20-1
Canceling ________ Sheet No. 20-1

P.S.C. ELECTRIC NO. 8

Tariff F.T.
(Franchise Tariff)

AVAILABILITY OF SERVICE

Where a city or town within the territory of Kentucky Power (Company) requires the Company to pay a percentage of revenues from certain customer classifications collected within such city or town of the right to erect the Company's poles, conductors, or other apparatus along, over, under, or across such city's or town's streets, alleys, or public grounds, the Company shall increase the rates and charges to such customer classifications within such city or town by a like percentage. The aforesaid charge shall be separately stated and identified on each affected customer's bill.

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E.K. WAGNER DIRECTOR REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2005- dated

TARIFF T. S.
(Temporary Service)

AVAILABILITY OF SERVICE.

Available for temporary lighting and power service where capacity is available.

RATE.

Temporary service will be supplied under any published tariff applicable to the class of business of the Customer, when the Company has available unsold capacity of lines, transforming and generating equipment, with an additional charge of the total cost of connection and disconnection.

MINIMUM CHARGE.

The same minimum charge as provided for in any applicable tariff, shall be applicable to such temporary service and for not less than one full monthly minimum.

TERM.

Variable.

SPECIAL TERMS AND CONDITIONS.

A deposit equal to the full estimated amount of the bill and/or construction costs under this tariff may be required.

This tariff is not available to customers permanently located, whose energy requirements are of a seasonal nature.

See Terms and Conditions of Service.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE
(Tariff D.S.M.C.)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., S.G.S., M.G.S., M.G.S.-T.O.D., L.G.S., Q.P., C.I.P.-T.O.D., C.S.-I.R.P., and M.W.

RATE.

1. The Demand-Side Management (DSM) clause shall provide for periodic adjustment per KWH of sales equal to the DSM costs per KWH by customer sector according to the following formula:

$$\text{Adjustment Factor} = \frac{DSM(c)}{S(c)}$$

Where DSM is the cost by customer sector of demand-side management programs, net lost revenues, incentives, and any over/under recovery balances; (c) is customer sector; and S is the adjusted KWH sales by customer sector.

2. Demand-Side Management (DSM) costs shall be the most recent forecasted cost plus any over/under recovery balances recorded at the end of the previous period.

   a. Program costs are any costs the Company incurred associated with demand-side management which were approved by the Kentucky Power Company DSM Collaborative. Examples of costs to be included are contract services, allowances, promotion, expenses, evaluation, lease expense, etc. by customer sector.

   b. Net lost revenues are the calculated net lost revenues by customer sector resulting from the implementation of the DSM programs.

   c. Incentives are a shared-savings incentive plan consisting of one of the following elements: The efficiency incentive, which is defined as 15 percent of the estimated net savings associated with the programs. Estimated net savings are calculated based on the California Standard Practice Manual's definition of the Total Resources Cost (TRC) test, or the maximizing incentive which is defined as 5 percent of actual program expenditures if program savings cannot be measured.

   d. Over/ Under recovery balances are the total of the differences between the following:

      (i) the actual program costs incurred versus the program costs recovered through DSM adjustment clause, and

      (ii) the calculated net lost revenues realized versus the net lost revenues recovered through the DSM adjustment clause, and

      (iii) the calculated incentive to be recovered versus the incentive recovered through the DSM adjustment clause.

3. Sales (S) shall be the total ultimate KWH sales by customer sector less non-metered, opt-out and lost revenue impact KWHs by customer sector.

4. The provisions of the Demand-Side Management Adjustment Clause will be effective for the period ending December 31, 2005. (T)

(Cont'd. On Sheet No. 22-2)

KENTUCKY POWER COMPANY

Original SHEET NO. 22-2
CANCELING ______ SHEET NO. 22-2

P.S.C. ELECTRIC NO. 7

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE (Cont'd.)
(Tariff D.S.M.C.)

RATE. (Cont'd.)

5. The DSM adjustment shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments which shall include data and information as may be required by the Commission.

6. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

7. The resulting range for each customer sector per KWH during the three-year Experimental Demand-Side Management Plan is as follows:

		CUSTOMER SECTOR		
		RESIDENTIAL ($ Per KWH)	COMMERCIAL ($ Per KWH)	INDUSTRIAL* ($ Per KWH)
Floor Factor	=	0.000320	0.000041	- 0 -
Ceiling Factor	=	0.000624	0.000068	- 0 -

8. The DSM Adjustment Clause factor ($ Per KWH) for each customer sector which fall within the range defined in Item 7 above is as follows:

	CUSTOMER SECTOR		
	RESIDENTIAL	COMMERCIAL	INDUSTRIAL*
DSM (c)	$ 306,288	$ 14,259	- 0 -
S (c)	649,080,700	261,854,100	- 0 -
Adjustment Factor $	0.000472	0.000055	- 0 -

*The Industrial Sector has been discontinued pursuant to the Commission's Order dated September 28, 1999.

DATE OF ISSUE September 26, 2005 EFFECTIVE DATE Services rendered on and after October 27, 2005

ISSUED BY ERROL K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

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KENTUCKY POWER COMPANY

Original Sheet No. 23-1
Canceling ______ Sheet No. 23-1

P.S.C. ELECTRIC NO. 8

NET MERGER SAVINGS CREDIT (N.M.S.C.)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., S.G.S., M.G.S., M.G.S.-T.O.D., L.G.S., Q.P., C.I.P.-T.O.D., C.S.- I.R.P., M.W., O.L., and S.L.

RATE.

The Net Merger Savings Credit shall provide for a monthly adjustment to base rates on a rate per KWH of monthly consumption. The Net Merger Savings Credit shall be calculated according to the following formula:

Net Merger Savings Credit = M.S.F. + B.A.F.

Where:

(M.S.F.) Is the Merger Savings Factor per KWH which is based on the total Company net savings that are to be distributed to the Company's Kentucky retail jurisdictional customers in each 12-month period.

	Net Savings to be Distributed	Merger Savings Factor (M.S.F.)	Balancing Adjustment Factor (B.A.F.)
Year 1*	$ 1,463,815	.021¢ per KWH	0 ¢
Year 2	2,553,660	.037¢ per KWH	.0007¢ per KWH
Year 3	3,184,645	.045¢ per KWH	.0009¢ per KWH
Year 4	3,695,003	.051¢ per KWH	.0018¢ per KWH
Year 5	4,037,167	.055¢ per KWH	.0030¢ per KWH
Year 6	4,299,432	.057¢ per KWH	.0025¢ per KWH
Year 7	4,504,920	.059¢ per KWH	
Year 8	4,626,369	.059¢ per KWH	
Year 9	5,242,785	.066¢ per KWH	

*The Net Merger Savings Credit will begin in the first full billing month available following thirty days from the consummation of the merger and will continue until the effective date of a Commission order changing the Company's base rates after Year 8 of this tariff.

(B.A.F.) Is the Balancing Adjustment Factor per KWH for the second through the twelfth months of the current distribution year, which reconciles any over-, or under-distribution of the net savings from prior periods. The B.A.F. will be determined by dividing the difference between amounts which were expected to be distributed and the amounts actually distributed from the application of the Net Merger Savings Credit from the previous year by the expected Kentucky retail jurisdictional KWH. The final B.A.F. will be applied to customer billings in the second month following the effective date of a Commission order changing the Company's base rates after Year 8 of this tariff.

TERMS OF DISTRIBUTION.

1. The total distribution to the Company's customers will, in no case, be less than the sum of the amounts shown for the first eight years above.

2. On or before the 21st of the first month of each distribution year following Year 1, the Company will file with the Commission a status report of the Net Merger Savings Credit. Such report shall include a statement showing the amounts, which were expected to be distributed, and the amounts actually distributed in previous periods, along with a calculation of the B.A.F., which will be implemented with customer billings in the second month of that distribution year to reconcile any previous over-or under-distributions.

3. The Net Merger Savings Credit shall be applied to the customer's bill following the rates and charges for electric service, but before application of the school tax, the franchise fee, sales tax or similar items.

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E.K., WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

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KENTUCKY POWER COMPANY

Original Sheet No. 24-1
Canceling ______ Sheet No. 24-1

P.S.C. ELECTRIC NO. 8

RIDER E.C.S.
(Emergency Curtailable Service Rider)

AVAILABILITY OF SERVICE.

Available for Emergency Curtailable Service (ECS) to customers normally taking firm service under Tariffs Q.P. and C.I.P.-T.O.D. for their total capacity requirements from the Company. The Customer must have an on-peak curtailable demand not less than 1MW and will be compensated for kWh curtailed under the provisions of this Rider.

CONDITIONS OF SERVICE.

1. The Company reserves the right to curtail service to the Customer's ECS load when, in the sole judgment of the Company, an emergency condition exists on the American Electric Power (AEP) System. The Company shall determine that an emergency condition exists if curtailment of load served under this Rider is necessary in order to maintain service to the Company's other firm service customers according to the AEP System Emergency Operating Plan for generation capacity deficiencies.

2. The Company will endeavor to provide as much advance notice as possible of curtailments under this Rider including an estimate of the duration of such curtailments. However, the Customer's ECS load shall be curtailed within 30 minutes if so requested

3. In no event shall the Customer be subject to curtailment under the provisions of this Rider for more than 50 hours during any season. For purposes of this Rider, seasons are defined as follows:

Winter	December, January and February
Summer	June, July and August

No curtailments under this Rider shall occur in the remaining months, with the exception of test curtailments as specified under Item 6 below.

4. The Company and the Customer shall mutually agree upon the method which the Company shall use to notify the Customer of a curtailment under the provisions of this Rider. The method shall specify the means of communicating such curtailment (e.g., telephone, pager) and shall designate the Customer's representatives to receive said notification. The Customer is ultimately responsible for receiving and acting upon a curtailment notification from the Company.

5. No responsibility or liability of any kind shall attach to or be incurred by the Company or the AEP System for, or on account of, any loss, cost, expense or damage caused by or resulting from, either directly or indirectly, any curtailment of service under the provisions of this Rider.

6. The Company reserves the right to test and verify the Customer's ability to curtail. Such test will be limited to one Curtailment per contract term. Any failure of the customer to comply with a request to curtail load will entitle the Company to call for one additional test. The Company agrees to notify the Customer as to the month in which the test will take place, and will consider avoiding tests on days which may cause a unique hardship to the Customer's overall operation. There shall be no credits for test curtailments nor charge for failure to curtail during a test.

7. The Company reserves the right to discontinue service to the Customer under this Rider if the Customer fails to curtail under any circumstances twice during a 12-month period as requested by the Company.

8. The Customer shall not receive credit for any curtailment periods in which the Customer's curtailable load is already down for an extended period due to a planned or unplanned outage as a result of vacation, renovation, repair, refurbishment, force majeure, strike, or any event other than the customer's normal operating conditions.

(Continued on Sheet No. 24-2)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2005- dated

RIDER E.C.S. (Cont'd)
(Emergency Curtailable Service Rider)

ECS CURTAILMENT OPTION.

The Customer shall select one of the following ECS Curtailment Options under this Rider:

	Credit	Maximum Duration
Option A	35 ¢/KWH	4 hours
Option B	50 ¢/KWH	8 hours

The ECS Curtailment Option Credit shall be applicable to the KWH curtailed under this Rider. The Maximum Duration is the
maximum number of hours per curtailment event for which load may be curtailed under the provisions of this Rider. The Company, to the extent practical, will endeavor to minimize the curtailment duration. However, the Customer shall receive a minimum of 2 hours credit per curtailment event

ECS CONTRACT CAPACITY.

Each Customer shall have an ECS Contract Capacity to be considered as emergency curtailable capacity under this Rider. The Customer shall specify the Non-ECS Demand, which shall be the demand at or below which the Customer will remain during curtailment periods. The ECS Contract Capacity shall be the difference between the Customer's typical on-peak demand and the Customer's specified Non-ECS Demand. The Company shall determine the Customer's typical on-peak demand, as agreed upon by the Company and the Customer. For the purpose of this Rider, the on-peak billing period is defined as 7:00 a.m. to 11:00 p.m., local time, for all weekdays, Monday through Friday.

The Customer may modify the amount of ECS Contract Capacity and/or the choice of Option no more than once prior to each season. Modifications must be received by the Company in writing no later than 30 days prior to the beginning of the season.

CURTAILED DEMAND.

For each curtailment period, Curtailed Demand shall be defined as the difference between the Customer's typical on-peak demand and the maximum 15-minute integrated demand during that curtailment period.

ECS ENERGY.

Period ECS Energy shall be defined as the product of the Curtailed Demand and the number of hours for each curtailment period. ECS Energy shall be equal to the sum of all Period ECS Energy for the calendar month.

MONTHLY CREDIT.

The Monthly Credit shall be equal to the product of the ECS Energy and the applicable Curtailment Option Credit less any charges computed for failure to curtail. The Monthly Credit will be provided to the Customer by check within 30 days after the end of the month in which the curtailment occurred. This amount will be recorded in the Federal Energy Regulatory Commission's Uniform System of Accounts under Account 555, Purchased Power, and will be recorded in a sub account so that the separate identify of this cost is preserved.

(Cont'd on Sheet No. 24-3)

RIDER E.C.S. (Cont'd)
(Emergency Curtailable Service Rider)

FAILURE TO CURTAIL.

If the Customer fails to fully comply with a request for curtailment under the provisions of this Rider, then the Noncompliance Demand shall be the difference between the maximum 15-minute integrated demand during the curtailment period and the Non-ECS Demand. Noncompliance Energy shall e the Noncompliance Demand multiplied by the number of hours for the curtailment period. For customers with kVa demands, Noncompliance Energy shall be multiplied by the Customer's average monthly power factor. Noncompliance Energy shall be billed at a rate equal to 50% of the Customer's selected ECS Curtailment Option Credit.

TERM.

Contracts under this Rider shall e made for an initial period of 1 season and shall remain in effect thereafter until either party provides to the other at least 30 days' written notice prior to the start of the next season of its intention to discontinue service under the terms of this Rider.

SPECIAL TERMS AND CONDITIONS.

Individual Customer information, including, but not limited to, ECS Contract Capacity and ECS Curtailment Option, shall remain confidential.

KENTUCKY POWER COMPANY

Original Sheet No. 25-1
Canceling ______ Sheet No. 25-1

P.S.C. ELECTRIC NO. 8

RIDER P.C.S.
(Price Curtailable Service Rider)

AVAILABILITY OF SERVICE.

Available for Price Curtailable Service (PCS) to customers normally taking firm service under Tariffs Q.P. and C.I.P.-T.O.D. for their total capacity requirements from the Company. The Customer must have an on-peak curtailable demand not less than 1 MW and will be compensated for kWh curtailed under the provisions of this Rider.

CONDITIONS OF SERVICE.

1. The Company reserves the right to curtail service to the Customer's PCS load at the Company's sole discretion.
2. The Company will endeavor to provide as much advance notice as possible of curtailments under this Rider including an estimate of the duration of such curtailments. However, the Customer's PCS load shall be curtailed within 1 hour if so requested.
3. For purposes of this Rider, seasons are defined as follows:

Winter	December, January and February
Spring	March, April and May
Summer	June, July and August
Fall	September, October and November

4. The Company and the Customer shall mutually agree upon the method which the Company shall use to notify the Customer of a curtailment under the provisions of this Rider. The method shall specify the means of communicating such curtailment (e.g., telephone, pager) and shall designate the Customer's representatives to receive said notification. The Customer is ultimately responsible for receiving and acting upon a curtailment notification from the Company.
5. No responsibility or liability of any kind shall attach to or be incurred by the Company or the AEP System for, or on account of, any loss, cost, expense or damage caused by or resulting from, either directly or indirectly, any curtailment of service under the provisions of this Rider.
6. The Company reserves the right to test and verify the Customer's ability to curtail. Such test will be limited to one curtailment per contract term. Any failure of the customer to comply with a request to curtail load will entitle the Company to call for one additional test. The Company agrees to notify the Customer as to the month in which the test will take place, and will consider avoiding tests on days, which may cause a unique hardship to the Customer's overall operation. There shall be no credits for test curtailments nor charge for failure to curtail during a test.
7. The Company reserves the right to discontinue service to the Customer under this Rider if the Customer fails to curtail under any circumstances twice during a 12-month period as requested by the Company.
8. The Customer shall not receive credit for any curtailment periods in which the Customer's curtailable load is already down for an extended period due to a planned or unplanned outage as a result of vacation, renovation, repair, refurbishment, force majeure, strike, or any event other than the customer's normal operating conditions.

(Continued on Sheet No. 25-2)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E.K. WAGNER DIRECTORY OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2005- dated

RIDER P.C.S. (Cont'd)
(Price Curtailable Service Rider)

PCS CURTAILMENT OPTION.

The Customer shall select one of the following Maximum Duration Options under this Rider:

	Maximum Duration
Option A	4 hours
Option B	8 hours
Option C	16 hours

The Maximum Duration is the maximum number of hours per curtailment event for which load may be curtailed under the provisions of this Rider. The Customer shall receive a minimum of 2 hours credit per curtailment event.

The Customer shall specify the Maximum Number of Days during the season that the Customer may be requested to curtail The Customer shall also specify the Minimum Price at which the customer would be willing to curtail. The Company, at its discretion will determine whether the Customer shall be curtailed give the Customer's specified PSC curtailment options.

PCS CONTRACT CAPACITY.

Each Customer shall have an PCS Contract Capacity to be considered as price curtailable capacity under this Rider. The Customer shall specify the Non-PCS Demand, which shall be the demand at or below which the Customer will remain during curtailment periods. The PCS Contract Capacity shall be the difference between the Customer's typical on-peak demand and the Customer's specified Non-PCS Demand. The Company shall determine the Customer's typical on-peak demand, as agreed upon by the Company and the Customer. For the purpose of this Rider, the on-peak billing period is defined as 7:00 a.m. to 11:00 p.m., local time, for all weekdays, Monday through Friday.

The Customer may modify the amount of PCS Contract Capacity and/or the choice of Option no more than once prior to each season. Modifications must be received by the Company in writing no later than 30 days prior to the beginning of the season.

CURTAILED DEMAND.

For each curtailment period, Curtailed Demand shall be defined as the difference between the Customer's typical on-peak demand and the maximum 15-minute integrated demand during that curtailment period.

CURTAILMENT CREDIT

Period PCS Energy shall be defined as the product of the Curtailed Demand and the number of hours for each curtailment period. The Curtailment credit shall be equal to the product of the Period PCS Energy and the greater of the following: (a) 80% of the daily price index for Into Cinergy On-Peak for the date of curtailments stated in Power Markets Week's Daily Price Report, (b) the Minimum Price as specified by the Customer or (c) 3.5 cents/kWh.

MONTHLY CREDIT.

The Monthly Credit shall be equal to the product of the PCS Energy and the applicable Curtailment Option Credit less any charges computed for failure to curtail. The Monthly Credit will be provided to the Customer by check within 30 days after the end of the month in which the curtailment occurred. This amount will be recorded in the Federal Energy Regulatory Commission's Uniform System of Accounts under Account 555, Purchased Power, and will be recorded in a subaccount so that the separate identify of this cost is preserved.

(Cont'd on Sheet No. 25-3)

KENTUCKY POWER COMPANY

Original Sheet No. 25-3
Canceling_____ Sheet No. 25-3

P.S.C. ELECTRIC NO. 8

RIDER P.C.S. (Cont'd)
(Price Curtailable Service Rider)

FAILURE TO CURTAIL.

If the Customer fails to fully comply with a request for curtailment under the provisions of this Rider, then the Noncompliance Demand shall be the difference between the maximum 15-minute integrated demand during the curtailment period and the Non-PCS Demand. Noncompliance Energy shall be the Noncompliance Demand multiplied by the number of hours for the curtailment period. Noncompliance Energy shall be billed at a rate equal to the applicable Curtailment Credit for the curtailment period during which the Customer failed to fully comply.

TERM.

Contracts under this Rider may be made for an initial period of 1 season and shall remain in effect thereafter until either party provides to the other at least 30 days' written notice prior to the start of the next season of its intention to discontinue service under the terms of this Rider.

SPECIAL TERMS AND CONDITIONS.

Individual Customer information, including, but not limited to, PCS Contract Capacity and PCS Curtailment Options, shall remain confidential.

TARIFF N.U.G.
(Non-Utility Generator)

AVAILABILITY OF SERVICE.

This tariff is applicable to customers with generation facilities which have a total design capacity of over 1,000 kW that intend to schedule, deliver and sell the net electric output of the facility at wholesale, and who require Commissioning Power, Startup Power and/or Station Power service from the Company.

Service to any load that is electrically isolated from the Customer's generator shall be separately metered and provided in accordance with the generally available demand-metered tariff appropriate for such service to the Customer.

This tariff is not available for standby, backup, maintenance, or supplemental service for wholesale or retail loads served by customer's generator.

DEFINITIONS.

1. **Commissioning Power** - The electrical energy and capacity supplied to the customer prior to the commercial operation of the customer's generator, including initial construction and testing phases.
2. **Station Power** - The electrical energy and capacity supplied to the customer to serve the auxiliary loads at the customer's generation facilities, usually when the customer's generator is not operating. Station Power does not include Startup Power.
3. **Startup Power** - The electrical energy and capacity supplied to the customer following a planned or forced outage of the customer's generator for the purpose of returning the customer's generator to synchronous operation.

COMMISSIONING POWER SERVICE.

Customers requiring Commissioning Power shall take service under Tariff T.S. or by special agreement with the Company.

The Customer shall coordinate its construction and testing with the Company to ensure that the customer's operations do not cause any undue interference with the Company's obligations to provide service to its other customers or impose a burden on the Company's system or any system interconnected with the Company.

STATION POWER SERVICE.

Customers requiring Station Power shall take service under the generally available demand-metered tariff appropriate for the customer's Station Power requirements.

Station Contract Capacity – The Customer shall contract for a definite amount of electrical capacity in kW sufficient to meet the maximum Station Power requirements that the Company is expected to supply under the generally available demand-metered tariff appropriate for the customer.

STARTUP POWER SERVICE.

Customers requiring Startup Power have the option of contracting for such service under the terms of this tariff or under the generally available demand-metered tariff appropriate for the customer's Startup Power requirements.

Startup Contract Capacity – The Customer shall contract for a definite amount of electrical capacity in kW sufficient to meet the maximum Startup Power requirements that the Company is expected to supply.

Startup Duration – The Customer shall contract for a definite number of hours sufficient to meet the maximum period of time for which the Company is expected to supply Startup Power.

Startup Frequency – The Customer shall contract for a definite number of startup events sufficient to meet the maximum number of times per year that the Company is expected to supply Startup Power.

Other Startup Characteristics – The customer shall provide to the Company other information regarding the customer's Startup Power requirements, including, but not limited to, anticipated time-of-use and seasonal characteristics.

Notification Requirement - Whenever Startup Power is needed, the Customer shall provide advance notice to the Company.

(Cont'd. on Sheet No. 26-2)

KENTUCKY POWER COMPANY

ORIGINAL SHEET NO. 26-2
CANCELING ________ SHEET NO. 26-2

PSC ELECTRIC NO. 8

TARIFF N.U.G. (Cont'd)
(Non-Utility Generator)

STARTUP POWER SERVICE. (cont'd)

Upon receipt of a request from the Customer for Startup Power Service under the terms of this tariff, the Company will provide the Customer a written offer containing the Notification Requirement, generation rates (including demand and energy charges) and related terms and conditions of service under which service will be provided by the Company. Such offer shall be based upon the Startup Contract Capacity, Startup Duration, Startup Frequency, and Other Startup Characteristics as specified by the customer. In no event shall the generation rates be less than the sum of the Tariff C.I.P.-T.O.D. Energy Charge, the Fuel Adjustment Clause, the System Sales clause, the Experimental Demand-Side Management Adjustment Clause, the Net Merger Savings Credit, Environmental Surcharge and the State Issues Stipulation charge. (T)

If the parties reach an agreement based upon the offer provided to the customer by the Company, a contract shall be executed that provides full disclosure of all rates, terms and conditions of service under this tariff, and any and all agreements related thereto.

Monthly Transmission and Distribution Rates

	Service Voltage		
	Subtransmission	Transmission	
Tariff Code	392	393	
Reservation Charge per kW	~~$ 3.25~~ *$4.59*	~~$ 2.28~~ *$2.54*	(I)

Reactive Demand Charge for each kiloVAR of maximum leading or lagging reactive demand in excess of 50% of the KW of monthly metered demand...$ ~~0.60~~ *0.72* per KVAR (I)

Delayed Payment Charge

This Tariff is net if account is paid in full within 15 days of date of bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

Monthly Billing Demand

The monthly billing demand in kW shall be taken each month as the highest single 15-minute integrated peak in kW as registered by a demand meter or indicator, less the Station Contract Capacity. The monthly billing demand so established shall in no event be less than the greater of (a) the Startup Contract Capacity or b) the customer's highest previously established monthly billing demand during the past 11 months.

Monthly Billing Energy

Interval billing energy shall be measured each 15-minute interval of the month as the total KWH registered by an energy meter or meters less the quotient of the Station Contract Capacity and four (4). In no event shall the interval billing energy be less than zero (0). Monthly billing energy shall be the sum of the interval billing energy for all intervals of the billing month.

(Cont'd on Sheet 26-3)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on or after October 27, 2005

ISSUED BY E.K. WAGNER (NAME) DIRECTOR OF REGULATORY AFFAIRS (TITLE) FRANKFORT, KENTUCKY (ADDRESS)

Issued by authority of an Order of the Public Service Commission in Case No. 2005- dated

TARIFF N.U.G. (Cont'd)
(Non-Utility Generator)

TRANSMISSION SERVICE.

Transmission Provider – The entity providing transmission service to customers in the Company's service territory. Such entity may be the Company or a regional transmission entity.

Prior to taking service under this tariff, the Customer must have a fully executed Interconnection and Operation Agreement with the Company and/or the Transmission Provider or an unexecuted agreement filed with the Federal Energy Regulatory Commission under applicable procedures.

Should the Transmission Provider implement charges for Transmission Congestion, the Company shall provide 30 days written notice to the customer. Upon the expiration of such notice period, should the customer's use of Startup Power result in any charges for Transmission Congestion from the Transmission Provider, such charges, including any applicable taxes or assessments, shall be paid by or passed through to the customer without markup. Transmission Congestion is the condition that exists when market participants seek to dispatch in a pattern that would result in power flows that cannot be physically accommodated by the system.

TERM OF CONTRACT.

Contracts under this tariff will be made for an initial period of not less than one year and shall remain in effect thereafter until either party shall give at least 6 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than one year.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

The Company may not be required to supply capacity in excess of that contracted for except by mutual agreement. Contracts will be made in multiples of 100 kW.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff shall not obligate the Company to purchase or pay for any capacity or energy produced by the Customer's generator.

Customers desiring to provide Startup and Station Power from commonly owned generation facilities that are not located on the site of the customer's generator (remote self-supply), shall take service under the terms and conditions contained within the applicable Open Access Transmission Tariff as filed with and accepted by the Federal Energy Regulatory Commission.

KENTUCKY POWER COMPANY

ORIGINAL SHEET NO. 27-1
Canceling ________ SHEET NO. 27-1

P.S.C. ELECTRIC NO. 8

Tariff N.M.S. (Net Metering Service)

AVAILIBILITY OF SERVICE.

Available to customers who own and operate an eligible electric generating facility designed to operate in parallel with the Company's system. Customers served under this tariff must also take service from the Company under the applicable standard service tariff. The total rated generating capacity of all customers served under this tariff shall be limited to one tenth of one percent (0.1%) of the Company's single hour peak load during the previous year.

CONDITIONS OF SERVICE.

1. For the purposes of this tariff, an eligible customer-generator's electric generating facility must comply with all of the following requirements:
   a. generates electricity using only solar energy;
   b. has a rated capacity of not more than fifteen (15) kilowatts;
   c. is owned and operated by the customer and is located on the customer's premises;
   d. is intended for the primary purpose of supplying all or part of the customer's own electricity requirements; and
   e. is designed and installed to operate in parallel with the Company's electric distribution system without adversely affecting the operation of equipment and service of the Company and its customers and without presenting safety hazards to Company and customer personnel.

2. A Customer seeking to interconnect an eligible electric generating facility to the Company's system must submit to the Company's designated personnel a completed Interconnection Application, and a one-line diagram showing the configuration of the proposed net metering facility. The Company will provide copies of all applicable forms upon request.

3. An Interconnection Agreement between the Company and the eligible customer-generator must be executed before the net metering facility may be interconnected with the Company's system.

4. All generator equipment and installations must comply with the Company's Technical Requirements. All generator equipment shall be installed in accordance with the manufacturer's specifications as well as all applicable provisions of the National Electrical Code and state and local codes. All generator equipment and installations shall comply with all applicable safety, performance and power quality standards established by the National Electrical Code, the Institute of Electrical and Electronic Engineers and accredited testing laboratories.

5. The Customer shall provide the Company proof of qualified installation of the net metering facility. Certification by a licensed electrician shall constitute acceptable proof.

6. The Customer shall install, operate, and maintain the electric generating facility in accordance with the manufacturer's suggested practices for safe, efficient, and reliable operation in parallel with the Company's system.

(Cont'd on Sheet 27-2)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Services rendered on and after October 28, 2005

ISSUED BY E. K. WAGNER (NAME) DIRECTOR REGULATORY SERVICES (TITLE) FRANKFORT, KENTUCKY (ADDRESS)

Issued pursuant to an Order by the Public Service Commission in Case No. 2005- dated

Tariff N.M.S. (Net Metering Service) (Cont'd)

7. The Customer must provide a visibly open, lockable, manual disconnect switch, which is accessible by the Company and is clearly labeled.

8. The Company may, at its own discretion, isolate any electric generating facility if the Company has reason to believe that continued interconnection with the electric generating facility creates or contributes to a system emergency.

9. The Company may perform reasonable on-site inspections to verify the proper installation and continuing safe operation of the net metering facility and the interconnection facilities, at reasonable times and upon reasonable advance notice to the net metering customer.

10. A customer operating an electric generating facility shall maintain homeowners, commercial or other insurance providing coverage in the amount of at least one hundred thousand dollars ($100,000) for the liability of the insured against losses or damages arising from the use of the customer's electric generating facility. The customer must submit evidence of such insurance to the Company with the Interconnection Application. The Company's receipt of evidence of liability insurance does not imply an endorsement of the terms and conditions of the coverage.

11. An eligible customer-generator installation is transferable to other persons or service locations only upon notification to the Company and verification that the installation is in compliance with all applicable safety and power quality standards. All other conditions of service apply.

METERING.

Net energy metering shall be accomplished using a standard kilowatt-hour meter capable of measuring the flow of electricity in two (2) directions. If the existing electrical meter installed at the customer's facility is not capable of measuring the flow of electricity in two directions, the customer shall be responsible for all expenses for the purchase and installation of an appropriate meter or meters with such capability. In the case where two meters are used, the reading of the meter measuring the flow of energy from the customer to the Company shall be subtracted from the reading of the meter measuring the flow of energy from the Company to the customer to obtain a measurement of net kWh for billing purposes.

MONTHLY CHARGES.

Monthly charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the Company's standard service tariff under which the customer would otherwise be served, absent the customer's electric generating facility. Energy charges under the customer's standard tariff shall be applied to the customer's net energy for the billing period to the extent that the net energy exceeds zero. If the customer's net energy is zero or negative during the billing period, the customer shall pay only the non-energy charge portions of the standard tariff bill. If the customer's net energy is negative during a billing period, the customer shall be credited in the next billing period for the kWh difference. If time-of-day metering is used, energy flows in both directions shall be netted and accounted for at the specific time-of-use in accordance with the provisions of the customer's standard tariff and this Net Metering Service Tariff. When the customer elects to no longer take service under this Net Metering Service Tariff, any unused credit shall revert to the Company. Excess electricity credits are not transferable between customers or locations.

(Cont'd on Sheet 27-3)

Tariff N.M.S. (Net Metering Service) (Cont'd)

OTHER CHARGES.

The customer is responsible for all equipment and installation costs of the electric generating facility.

As specified in the Interconnection Application, the customer must pay a non-refundable application fee of $50. This fee includes the cost of inspection of the customer's electric generating facility if the Company deems such inspection necessary.

Should the Company determine that an interconnection study is required, the Company will advise the customer of the estimated additional cost of performing such study. Upon payment by the customer of the estimated study costs, the Company will proceed with the interconnection study to determine if installation of the customer's electric generating facility will have significant impact on the Company's system.

Should construction or upgrades of the Company's system be required in order to interconnect the customer's electric generating facility, additional charges to cover costs incurred by the Company shall be determined by the Company and paid by the customer.

The customer shall pay any additional charges, as determined by the Company, for equipment, labor, metering, testing or inspections requested by the customer.

TERM OF CONTRACT.

Any contract required under this tariff shall be the same as that required under the customer's applicable standard service tariff.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service and all provisions of the standard service tariff under which the customer takes service.

TECHNICAL REQUIREMENTS.

The technical requirements for interconnection of Net Metering Installations to the Company Distribution System are as follows: Interconnection enables the Net Metering Installation to operate in parallel with the Company Distribution System. An Interconnection Application Screening and Interconnection Study, as described in Company's Interconnection Procedures, are used to determine the impact of the Net Metering Installation on the Company Distribution System beyond the Point of Common Coupling.

The standard, IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems", contains the majority of the technical requirements necessary for interconnection. IEEE 1547 is limited to an aggregate capacity of 10 MVA or less interconnected at typical primary and/or secondary voltages. IEEE 1547 does not address planning, designing, operating, or maintaining the utility's distribution system and it does not identify or address all of the potential system impact the proposed Net Metering Installation may create beyond the Point of Common Coupling. Due to the limitations of IEEE 1547, additional technical requirements are contained herein.

(Cont'd on Sheet 27-4)

Tariff N.M.S. (Net Metering Service) (Cont'd)

TECHNICAL REQUIREMENTS. (Cont'd)

These Technical Requirements are supplementary to and do not intentionally conflict with or supersede applicable laws, ordinances, rules or regulations established by Federal, State and other governmental bodies. The Customer is responsible for conforming to all applicable laws, ordinances, rules or regulations established by Federal, State and other governmental bodies. Additional requirements for interconnection may be imposed by the Transmission System Operator to address Transmission System operating issues related to the proposed Net Metering Installation. Additional requirements may also be necessary to comply with the requirements of other approved tariffs associated with the Company or other third parties providing services.

To assure that the safety, reliability and power quality of the Distribution system is not degraded by the interconnection of the Net Metering Installation:

1) The Net Metering Installation shall comply with the Technical Requirements stated herein.

2) Any Distribution System modifications and/or modifications to the Net Metering Installation identified by the Interconnection Study, as described in the Interconnection Procedures, shall be completed.

3) The Net Metering Installation shall be operated and maintained as agreed upon by the parties.

The Net Metering Installation shall comply with the requirements specified in IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems" and the other technical requirements stated herein.

IEEE publications are available from the Institute of Electrical and Electronics Engineers, 443 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331 (http://standards.ieee.org/).

EQUIPMENT DESIGN REQUIREMENTS

Data for all major equipment proposed by the Customer to satisfy the Technical Requirements must be submitted for review and approval by the Company with the completed Interconnection Application. To facilitate review and approval, the Company will maintain a list of Pre-certified Equipment. The Company's List of Pre-certified Equipment is available upon request and contains Pre-certified Equipment types, makes and models of manufactured generating equipment and interconnection system components. This listing is based upon equipment certified by recognized national testing laboratories as suitable for interconnection with a distribution system based upon compliance with IEEE Standard 1547. Suitability for interconnection does not imply that Pre-certified Equipment may be interconnected without a study to determine system impact.

The use of equipment that is not Pre-certified may delay the Company's review and approval of the Customer's design. All interconnection equipment must be approved by the Company prior to being connected to the Company's Distribution System and before parallel operation is allowed.

The interconnection system hardware and software design requirements in the Technical Requirements are intended to assure protection of the Company's Distribution System. Any additional hardware and software necessary to protect equipment at the generation facility is solely the responsibility of the Customer to determine, design, and apply.

(Cont'd on Sheet 27-5)

Tariff N.M.S. (Net Metering Service) (Cont'd)

TECHNICAL REQUIREMENTS. (Cont'd)

ISOLATING DEVICE

A group-operated isolating device must be located at the Point of Common Coupling. The isolating device must be accessible to the Company's personnel at all times and be suitable for use by the Company as a protective tagging location. The isolating device shall have a visible open gap when in the open position and be capable of being locked in the open position. The isolating device must comply with the applicable current standard that specifies the requirements for circuit breakers, reclosers and interrupting switches.

VOLTAGE UNBALANCE

Voltage unbalance is the maximum phase deviation from average as specified in ANSI C84.1.

The Customer is responsible for operating the proposed Net Metering Installation such that the voltage unbalance attributable to the Net Metering Installation shall not exceed 2.5% at the Point of Common Coupling.

INSTALLATION, MAINTENANCE AND TESTING

The Company reserves the right to witness Compliance Testing at the time of installation and maintenance testing of the interconnection system for compliance with the requirements of IEEE 1547.

The Customer is responsible for the periodic scheduled maintenance on the Net Metering Installation's interconnection system (relays, interrupting devices, control schemes, and batteries that involve the protection of the Company's Distribution System). A periodic maintenance program is to be established in accordance with the requirements of IEEE 1547. The Company may examine copies of the periodic test reports or inspection logs associated with the periodic maintenance program. Upon request Company shall be informed of the next scheduled maintenance and be able to witness the maintenance performed and any associated testing. For each test, a record shall be kept indicating the results of the tests made and the "as found" and "as left" calibration values. Visually setting, without verification, a calibration dial or tap is not considered an adequate calibration check.

The Company reserves the right, at the Company's initial expense, to install special test equipment as may be required to perform a disturbance analysis and monitor the operation and control of the Net Metering Installation to evaluate the quality of power produced by the Net Metering Installation.

(Cont'd on Sheet 27-6)

KENTUCKY POWER COMPANY

ORIGINAL SHEET NO. 27-6
Canceling ________ SHEET NO. 27-6

P.S.C. ELECTRIC NO. 8

AEP KENTUCKY POWER
A unit of American Electric Power

APPLICATION FOR NET METERING INTERCONNECTION WITH THE Kentucky Power Company DISTRIBUTION SYSTEM

Customer's Name: ______________________________

Address: ______________________________

Contact Person: ______________________________

Telephone Number(s): ______________________________

E-Mail Address: ______________________________

Service Location Address: ______________________________

Information Prepared and Submitted By: ______________________________

____
(Name, Address, and E-Mail Address)

Expected Energizing and Start-up Date: ______________________________

SOLAR GENERATOR'S INVERTER DATA

Manufacturer and Model: ______________________________

Kilowatt Rating: ____________ *(95° F at location)*   Kilovolt-Ampere Rating:: ____________ *(95° F at location)*

Voltage Rating: ____________   Ampere Rating: ____________

Have all necessary government permits and approvals been obtained for the project prior to this application?____Yes

Attach the following: One-line electrical diagram; layout sketch showing the physical location of the lockable, visible disconnect switch; and inverter specifications showing manufacturer test results documenting conformance with Company's technical requirements.

Attach application filing fee: $50 *(Check is payable to Kentucky Power Company. Send application and fee to: Kentucky Power Company, Attention: Manager of Customer Services, 12333 Kevin Avenue, Ashland, KY 41102)*

Name: ______________________________

Signature: ______________________________

Title: ______________________________

Date: ______________________________

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Services rendered on and after October 27, 2005

ISSUED BY E. K. WAGNER (NAME) DIRECTOR REGULATORY SERVICES (TITLE) FRANKFORT, KENTUCKY (ADDRESS)

Issued pursuant to an Order by the Public Service Commission in Case No. 2005 dated

KENTUCKY POWER COMPANY

Original Sheet No. 28-1
Canceling ______ Sheet No. 28-1

P.S.C. ELECTRIC NO. 8

TARIFF S.I.S.
(State Issues Settlement)

AVAILABILITY OF SERVICE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., S.G.S., M.G.S., M.G.S.-T.O.D., L.G.S., Q.P., C.I.P.-T.O.D., C.S.-I.R.P., M.W., O.L. and S.L. (N)

RATE.

	Service Tariff	
	All Other	C.I.P.-T.O.D.
Energy Charge per KWH per month	$0.000824	$0.000508

RATE CALCULATION.

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2004-00420 and the Settlement and Stipulation Agreement dated October 20, 2004 as filed and approved by the Commission, Kentucky Power Company is to recover from retail ratepayers the supplemental annual payments tied to the 18-year extension of the Rockport Unit Power Agreement (USPA). Kentucky Power will apply surcharges designed to enable recovery from each tariff class of customers, an annual supplemental payment of $5.1 million annually in Years 2005 through 2009, and then increases to $6.2 million annually in Years 2010 through 2021, and then decreases to $5,792,329 in Year 2022.

2. Kentucky Power will be entitled to receive these annual supplemental payments in addition to the base retail rates established by the Commission. The costs associated with the underlying Rockport Unit 1 and 2 UPSA will continue to be included in base rates.

3. The increased annual revenues will be generated by two different KWH rates, one for CIP-TOD tariff customers and one for All Other tariff customers.

4. The allocation of the additional revenues to be collected from the CIP-TOD tariff customers and All Other tariff customers will be based upon the total annual revenue of each of the two-customer classes. Once the additional revenues have been allocated between the two customer classes based upon total annual Kentucky retail revenue, the additional revenue will be collected within the two customer classes (CIP-TOD and All Other tariffs) on a KWH basis. The KWH rate to be applied to each of these two customer class groups shall be sufficient to generate that portion of the total increase in annual revenues equal to the percentage of total annual revenues produced by each of the two customer class groups (CIP-TOD and All Other tariffs).

5. The Stipulation and Settlement Agreement is made upon the express agreement by the Parties that the receipt by Kentucky Power of the additional revenues called for by Section III(1)(a) and III(1)(b) shall be accorded the ratemaking treatment set out in Section III. In any proceeding affecting the rates of Kentucky Power during the extension of the UPSA under this Stipulation and Settlement Agreement, the provisions of Section III are an express exception to Section VI(4) of the Stipulation and Settlement Agreement.

6. The State Issues Settlement surcharges will be applied to bills monthly and will be shown on the Customer's bill as a separate line item. (N)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Services rendered on or after October 27, 2005

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2005-0000 dated

KENTUCKY POWER COMPANY

ORIGINAL SHEET NO. 29-1
CANCELING ________ SHEET NO. 29-1

P.S.C. Electric No. 8

ENVIRONMENTAL SURCHARGE (E.S.)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., S.G.S., M.G.S., M.G.S.-T.O.D., L.G.S., Q.P., C.I.P.-T.O.D., C.S.-I.R.P., M.W., O.L., and S.L.

RATE.

1. The environmental surcharge shall provide for monthly adjustments based on a percent of revenues equal to the difference between the environmental compliance costs in the base period as provided in Paragraph 6 below and in the current period according to the following formula: (T)

$$\text{Monthly Environmental Surcharge Factor} = \frac{\text{Net KY Retail E(m)}}{\text{KY Retail R(m)}}$$

Where:

Net KY Retail E(m)	=	Monthly E(m) allocated to Kentucky Retail Customers, net of Over/(Under) Recovery Adjustment; Allocation based on Percentage of Kentucky Retail Revenues to Total Company Revenues in the Expense Month. (For purposes of this formula, Total Company Revenues do not include Non-Physical Revenues.)
KY Retail R(m)	=	Kentucky Retail Revenues for the Expense Month.

2. Monthly Environmental Surcharge Gross Revenue Requirement, E(m)

$$E(m) = CRR - BRR$$

Where:

CRR	=	Current Period Revenue Requirement for the Expense Month.
BRR	=	Base Period Revenue Requirement.

3. Base Period Revenue Requirement, BRR

$$BRR = ((RB_{KP(B)})(ROR_{KP(B)})/12) + OE_{KP(B)} + [((RB_{IM(B)})(ROR_{IM(B)})/12) + OE_{IM(B)}](.15)$$

Where:

$RB_{KP(B)}$	=	Environmental Compliance Rate Base for Big Sandy
$ROR_{KP(B)}$	=	Annual Rate of Return on Big Sandy Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return.
$OE_{KP(B)}$	=	Monthly Pollution Control Operating Expenses for Big Sandy.
$RB_{IM(B)}$	=	Environmental compliance Rate Base for Rockport
$ROR_{IM(B)}$	=	Annual Rate of Return on Rockport Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return.
$OE_{IM(B)}$	=	Monthly Pollution Control Operating Expenses for Rockport.

"KP(B)" identifies components from the Big Sandy Units – Base Period, and "IM(B)" identifies components from the Indiana Michigan Power Company's Rockport Units – Base Period.

The Rate Base for both Kentucky Power and Rockport should reflect the account balances as of June 30, 2005. The Operating Expense amounts should reflect the June 30, 2005 expense. The amounts reflect retirements or replacements resulting from the 1997 Plan, the 2003 Plan and the 2005 Plan. (T)

(Continued on Sheet 29-2)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on or after October 27, 2005

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No.2005-00068 dated September 7, 2005

KENTUCKY POWER COMPANY

ORIGINAL SHEET NO. 29-2
CANCELING ________ SHEET NO. 29-2

P.S.C. Electric No. 8

ENVIRONMENTAL SURCHARGE (E.S.) (Cont'd)

RATE (Cont'd)

The Rate of Return for Kentucky Power is a weighted average cost of capital calculation, reflecting the cost of debt as of June 30, 2005 and the rate of return on common equity authorized in Case No. 2005-00068. The Kentucky Power component in the Base Period Revenue Requirement is a result of the adoption of the Commission's Order in Case No. 2005-00341. As Kentucky Power's last general rate case had been settled, Kentucky Power proposed and the Commission accepted the use of the rate of return on common equity established in Case No. 2005-00068. (T)

The Rate of Return for Rockport should reflect the requirements of the Rockport Unit Power Agreement.

The Base Period Revenue Requirement will remain fixed until either a) a 2-year review case results in the roll-in of the surcharge into existing base rates, or b) further retirements or replacements of pollution control utility plant occur due to the installation of new pollution control utility plant associated with the approved compliance plan.

4. Current Period Revenue Requirement, CRR

$$CRR=[((RB_{KP(c)})(ROR_{KP(c)})/12) + OE_{KP(c)} + [((RB_{IM(c)})(ROR_{IM(c)})/12) + OE_{IM(c)}] (.15) - AS]\text{-}MEBC$$ (T)

Where:

$RB_{KP(C)}$	=	Environmental Compliance Rate Base for Big Sandy.
$ROR_{KP(C)}$	=	Annual Rate of Return on Big Sandy Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return.
$OE_{KP(C)}$	=	Monthly Pollution Control Operating Expenses for Big Sandy.
$RB_{IM(C)}$	=	Environmental Compliance Rate Base for Rockport.
$ROR_{IM(C)}$	=	Annual Rate of Return on Rockport Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return.
$OE_{IM(C)}$	=	Monthly Pollution Control Operating Expenses for Rockport.
AS	=	Net proceeds from the sale of SO_2 emission allowances, ERCs, and NOx emission allowances, reflected in the month of receipt. The SO_2 allowance sales can be from either EPA Auctions or the AEP Interim Allowance Agreement Allocations.
MEBC	=	Monthly Environmental Base Costs see paragraph 6 below (T)

"KP(C)" identifies components from the Big Sandy Units – Current Period, and "IM(C)" identifies components from the Indiana Michigan Power Company's Rockport Units – Current Period.

The Rate Base for both Kentucky Power and Rockport should reflect the current costs associated with the 1997 Plan and the 2003 Plan. The Rate Base for Kentucky Power should also include a cash working capital allowance based on the 1/8 formula approach, due to the inclusion of Kentucky Power's accounts receivable financing in the capital structure and weighted average cost of capital. The Operating Expenses for both Kentucky Power and Rockport should reflect the current operating expenses associated with the 1997 Plan, the 2003 Plan and the 2005 Plan. (T)

The Rate of Return for Kentucky Power is the weighted average cost of capital as authorized by the Commission in Case No. 2005-00341. (T)

(Cont'd on Sheet 29-3)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on or after October 27, 2005

ISSUED BY E.K.WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2005-00341 dated

ENVIRONMENTAL SURCHARGE (E.S.)

RATE (Cont'd)

The Rate of Return for Rockport should reflect the requirements of the Rockport Unit Power Agreement.

Net Proceeds from the sale of emission allowances and ERCs that reflect net gains will be a reduction to the Current Period Revenue Requirement, while net losses will be an increase.

The Current Period Revenue Requirement will reflect the balances and expenses as of the Expense Month of the filing.

5. Environmental costs "E" shall be the Company's costs of compliance with the Clean Air Act and those environmental requirements that apply to coal combustion wastes and by-products, as follows:

(a) cost associated with Continuous Emission Monitors (CEMS)

(b) costs associated with the terms of the Rockport Unit Power Agreement

(c) the Company's share of the pool capacity costs associated with Gavin scrubber(s)

(d) return on SO_2 allowance inventory

(e) costs associated with air emission fees

(f) over/under recovery balances between the actual costs incurred less the amount collected through the environmental surcharge

(g) costs associated with any Commission's consultant approved by the Commission

(h) costs associated with Low Nitrogen Oxide (NO_x) burners at the Big Sandy Generating Plant

(i) costs associated with the consumption of SO_2 allowances

(j) costs associated with the Selective Catalytic Reduction (SCR) at the Big Sandy Generating Plant

(k) costs associated with the upgrade of the precipitator at the Big Sandy Generating Plant

(l) costs associated with the over-fire air with water injection at the Big Sandy Generating Plant

(m) costs associated with the consumption of NO_x allowances

(n) return on NO_x allowance inventory

(o) 25% of the costs associated with the Reverse Osmosis Water System (the amount is subject to adjustment at subsequent 6 month surcharge reviews based on the documented utilization of of the RO Water System by the SCR)

(p) costs associated with operating approved pollution control equipment

(Cont'd on Sheet 29-4)

KENTUCKY POWER COMPANY

ORGINAL SHEET NO. 29-4
CANCELING ____________ SHEET NO. 29-4

P.S.C. Electric No. 8

ENVIRONMENTAL SURCHARGE (E.S.)

(q) costs associated with maintaining approved pollution control equipment including material and contract labor (excluding plant labor)

(r) the Company's share of the pool Capacity costs associated with the following:

- Amos Unit No. 3 CEMS, Low NO_x Burners and SCR
- Cardinal Unit No 1 CEMS, Low NO_x Burners and SCR
- Gavin Plant SCR and SCR Catalyst Replacement
- Gavin Unit No 1 and 2 Low NO_x Burners
- Kammer Unit Nos 1,2 and 3 CEMS, Over Fire Air and Duct Modification
- Mitchell Unit Nos 1 and 2 Water Injection, Low NO_x burners and Low NO_x burner Modification
- Mitchell Plant Common CEMS, Replace Burner Barrier Valves
- Muskingum River Unit No 1 Low NO_x Ductwork, Over Fire Air , Over Fire Air Modification, Water Injection and Water Injection Modification
- Muskingum River Unit No 2 Low NO_x Ductwork, Over Fire Air, Over Fire Air Modification and Water Injection
- Muskingum River Unit No 3 Over Fire Air, Over Fire Air Modification with NO_x Instrumentation
- Muskingum River Unit No 4 Over Fire Air with Modification
- Muskingum River Unit No 5 Low NO_x Burner with Modification and Weld Overlays and an SCR
- Muskingum River Common CEMS
- Phillip Sporn Unit No 2 Low NO_x Burners with Modifications
- Phillip Sporn Unit No 4 and 5 Low NO_x Burners and Modulating Injection Air system with Modifications
- Phillip Sporn Common CEMS and SO_3 injection system
- Rockport Unit No 1 and 2 Low NO_x Burners

(Cont'd on Sheet 29-5)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on or after October 27, 2005

ISSUED BY E. K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an order of the Public Service Commission in Case No. 2005-00000 dated

KENTUCKY POWER COMPANY

ORIGINAL SHEET NO. 29-5
CANCELING________SHEET NO. 29-5

P.S.C. Electric No. 8

ENVIRONMENTAL SURCHARGE (E.S.)

- Tanners Creek Unit No 1 Low NO_x Burners, with Modifications and Low NO_x Burners Leg Replacement
- Tanners Creek Unit No 2 and 3 Low NO_x Burners with Modifications
- Tanners Creek Unit No 4 Over Fire Air, Low NO_x Burners and ESP Controls Upgrade
- Tanners Creek Common CEMS
- Title V Air Emission Fees at Amos, Cardinal, Gavin, Kammer, Mitchell, Muskingum River, Phillip Sporn, Rockport and Tanners Creek plants.

6. The base monthly net cost from environmental compliance is as follows:

Billing Month	Base Net Environmental Costs
JANUARY	$2,531,784
FEBRUARY	3,003,995
MARCH	2,845,066
APRIL	2,095,535
MAY	1,514,859
JUNE	1,913,578
JULY	2,818,212
AUGUST	2,342,883
SEPTEMBER	2,852,305
OCTOBER	2,818,975
NOVEMER	2,598522
DECEMBER	1,407,969

(N)
(N)

7. The monthly environmental surcharge shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments which shall include data and information as may be required by the Commission.

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on or after October 27, 2005

ISSUED BY E. K.WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an order of the Public Service Commission in Case No. 2005-00000 dated

KENTUCKY POWER COMPANY

Original Sheet No. 30-1
Canceling ______ Sheet No. ____

P.S.C. ELECTRIC NO. 8

TARIFF N.C.R.
(Net Congestion Recovery)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., S.G.S., M.G.S., M.G.S.-T.O.D., L.G.S., Q.P., C.I.P.-T.O.D., C.S.-I.R.P., M.W., O.L., and S.L. (N)

RATE.

1. When the annual net congestion costs are above or below the annual base net costs from congestion, as provided in paragraph 3 below, an additional credit or charge equal to the product of the kWhs and a net congestion recovery factor (A) shall be made, where "A", calculated to the nearest 0.0001 mill per kilowatt-hour, is defined as set forth below.

   Net Congestion Recovery Factor (A) = (Ty - Tb) / Sy + BAF

   In the above formula "T" is Kentucky Power Company's (KPCo) annual net costs from congestion in the current (y) and base (b) periods, and "S" is the kWh sales in the current (y) period, all defined below.

2. The current period is defined as the 12 months ended September 30th each year. The net congestion costs for the current period is the difference between (implicit?) congestion costs and revenues from Financial Transmission Rights (FTR) and Auction Revenue Rights (ARR) as recorded on KPCo's books in account 447.

3. The base annual net congestion cost is $(3,002,352).

4. The kWh sales shall be the total ultimate kWh sales to retail customers for the current period.

5. The Net Congestion Recovery Factor (A) shall change annually on January 1st.

6. A Balancing Adjustment Factor (BAF) will be calculated on a per kWh basis for the second through the twelfth months of the year, which reconciles any over- or under-collection of additional revenues from prior periods. The BAF will be determined by dividing the difference between amounts which were expected to be collected and the amounts actually collected from the application of this tariff from the previous year by the expected Kentucky retail jurisdictional kWh.

7. For 2007 the Net Congestion Recovery Factor shall equal the difference between the current and base period net congestion costs times the number of months (n) that Tariff N.C.R. is in effect during the current period divided by 12. That product is divided by the kWh sales in the current period. The formula is shown below:

   Net Congestion Recovery Factor (A) = (Ty - Tb) * (n/12) / Sy (N)

DATE OF ISSUE September 26, 2005 DATE EFFECTIVE Service rendered on and after October 27, 2005

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No.2005- dated

AEP/Kentucky
Average Monthly Payment Plan
When Account History is not Available

Exhibit EKW-6

Ln. No. (1)	Month (2)	Total Actual Billing (3)	No. of Days in Billing Period (4)	AMP Billing (5)	Difference Between Actual and AMP Billing (6)	Calculation of Deferred Billing Balance (7)	Deferred Billing Amount Applied to AMP Bill (8)	Total AMP Payment (9)
1	1	$50.23	30	$50.00	$0.23	$0.23	$0.00	$50.00
2	2	$55.76	31	$52.00	$3.76	$3.99	$0.00	$52.00
3	3	$70.02	29	$59.00	$11.02	$15.01	$0.00	$59.00
4	4	$85.62	30	$65.00	$20.62	$35.63	$0.00	$65.00
5	5	$125.51	29	$78.00	$47.51	$83.14	$0.00	$78.00
6	6	$110.62	32	$83.00	$27.62	$110.76	$0.00	$83.00
7	7	$85.36	30	$83.00	$2.36	$113.12	$0.00	$83.00
8	8	$75.16	29	$82.00	-$6.84	$106.28	$0.00	$82.00
9	9	$70.44	32	$80.00	-$9.56	$96.72	$0.00	$80.00
10	10	$55.82	29	$78.00	-$22.18	$74.54	$0.00	$78.00
11	11	$40.93	33	$74.00	-$33.07	$41.47	$0.00	$74.00
12	12	$45.75	32	$71.00	-$25.25	$16.22	$0.00	$71.00
13	13	$57.46	30	$72.00	-$14.54	$0.68	$1.00	$73.00
14	14	$60.61	30	$73.00	-$12.39	-$12.71	$1.00	$74.00

Kentucky Power Company
Analysis of Reconnect Charges

Line No.	Description	Reconnect Regular Hours - Day Shift (1)	Reconnect Into O. T. Hours - Day Shift (2)	Reconnect Call-Out Hours - Day Shift (3)	Reconnect Sunday/ Holidays - Day Shift (4)	Collection Trip Charge (5)	Bad Check Charge (6)	Meter Test Charge (7)	Total Additional Revenues (8)
1	Hours Worked	1.0	1.0	2.0	2.0	0.6	0.0	1.5	
2	Transportation Hours	1.0	1.0	0.8	0.8	0.6	0.0	1.5	
3	Hourly Labor Rate	20.67	20.67	20.67	20.67	20.67	0.00	25.95	
4	Overtime Adj.	0.00	10.34	10.34	20.67	0.00	0.00	0.00	
5	Hourly Labor Rate W/O.T.	20.67	31.01	31.01	41.34	20.67	0.00	25.95	
6	Labor Cost (Line 1 * Line 5)	20.67	31.01	62.02	82.68	12.40	1.32	38.93	
7	Transportation Hourly Rate	7.21	7.21	7.21	7.21	7.21	0.00	7.21	
8	Trans. Cost (Line 7 * Line 2)	7.21	7.21	5.77	5.77	4.33	0.00	10.82	
9	Fringe Benefits Rate	0.4918	0.1348	0.1348	0.1348	0.4918	0.4918	0.4918	
10	Benefits Cost (Line 6 * Line 9)	10.17	4.18	8.36	11.15	6.10	0.65	19.15	
11	Bank Fees						4.56		
12	Total Cost (Line 6 + Line 8 + Line 10 = Line 12)	38.05	42.40	76.15	99.60	22.83	6.53	68.90	
13	Suggested Charge	38.00	42.00	76.00	100.00	23.00	7.00	69.00	
14	Current Charge	9.00	12.00	25.00	31.00	6.00	5.00	10.00	
15	Increase/(Decrease)	29.00	30.00	51.00	69.00	17.00	2.00	59.00	
16	12 Month 4/30/04 Actual No. of Trans.	5,122	452	305	13	16,106	1,722	3	
17	Total Additional Revenues	$148,538	$13,560	$15,555	$897	$273,802	$3,444	$177	$455,973
18	Less:State Income Tax at 7.19%								$32,784
19	Less:Federal Tax At 35%								$148,116
20	Net Income Effect								$275,073

Exhibit EKW-7

Kentucky P[illegible] Company
Twelve Months [illegible]g June 2005
Non-Recurring Charges
Monthly Break Down

Ln No (1)	Description (2)	Jul 04 (3)	Aug 04 (4)	Sep 04 (5)	Oct 04 (6)	Nov 04 (7)	Dec 04 (8)	Jan 05 (9)	Feb 05 (10)	Mar 05 (11)	Apr 05 (12)	May 05 (13)	Jun 05 (14)	Total (15)	Proposed Increase (16)	Proposed Increase Per Class (17)
	$9.00 Reconnect Charge															
1	Residential	580	609	589	539	486	218	217	146	239	444	457	337	4,861	$29.00	$140,969
2	Commerical	28	36	18	19	27	18	11	8	23	22	25	21	256	$29.00	$7,424
3	Public Authority	1						1						2	$29.00	$58
4	Industrial					1			1		1			3	$29.00	$87
5	Total	609	645	607	558	514	236	229	155	262	467	482	358	5,122		$148,538.00
	$12.00 into Overtime															
6	Residential	82	63	51	58	44	27	22	6	17	27	26	16	439	30.00	$13,170
7	Commerical	1	1	4	0	0	1	0	1	2	1	1	1	13	30.00	$390
8	Total	83	64	55	58	44	28	22	7	19	28	27	17	452		$13,560
	$25.00 Call Out															
9	Residential	49	50	33	31	23	8	7	7	16	22	30	16	292	51.00	$14,892
10	Commerical	2	2	1	1	1	0	1	0	1	1	2	0	12	51.00	$612
11	Industrial	0	0	0	0	1	0	0	0	0	0	0	0	1	51.00	$51
12	Total	51	52	34	32	25	8	8	7	17	23	32	16	305		$15,555
	$31.00 Sun. Holiday															
13	Residential	0	3	0	1	2	0	1	1	5	0	0	0	13	69.00	$897
	$6.00Collection Trip															
14	Residential	1337	1369	1458	1179	1117	1090	1345	1505	1532	1095	1040	872	14,939	17.00	$253,963
15	Commerical	102	108	98	86	96	91	105	74	120	88	83	72	1,123	17.00	$19,091
16	Public Authority	1	0	0	0	1	1	0	1	0	0	0	0	4	17.00	$68
17	School	0	0	0	6	0	0	0	0	0	0	0	0	6	17.00	$102
18	Industrial	1	0	1	3	2	1	3	1	3	1	1	1	18	17.00	$306
19	Mine Power	1	0	2	2	2	2	0	1	2	2	1	1	16	17.00	$272
20	Public Street Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	17.00	$0
21	Total	1442	1477	1559	1276	1218	1185	1453	1582	1657	1186	1125	946	16,106		$273,802
	$5.00															
	Bad Check Charge															
22	Residential	147	147	137	125	127	125	120	99	139	127	165	124	1,582	2.00	$3,164
23	Commerical	19	10	16	13	9	10	12	9	14	7	8	10	137	2.00	$274
24	Public Authority	0	0	0	0	0	0	0	0	1	0	0	0	1	2.00	$2
25	Industrial	1	0	0	0	0	0	0	0	0	0	0	0	1	2.00	$2
26	Mine Power	0	0	0	0	1	0	0	0	0	0	0	0	1	2.00	$2
27	Total	167	157	153	138	137	135	132	108	154	134	173	134	1,722		$3,444
	$10.00 Meter Test															
28	Residential	0	0	0	0	0	0	2	0	1	0	0	0	3	59.00	$177
29	Total															$455,973.00

Exhibit EKW-8

Kentucky Power Company
Non-Recurring Charges
by Customer Class
June 30, 2005

Ln No (1)	Description (2)	Reconnect $38.00 Charge (3)	Reconnect $42.00 Charge (4)	Reconnect $76.00 Charge (5)	Reconnect $100.00 Charge (6)	Collection Trip $23.00 Charge (7)	Bad Check $7.00 Charge (8)	Meter Test $69.00 Charge (9)	Class Revenue Increase (10)	Twelve Month June 2005 Additional Revenue (11)	Class Total Percent Change (12)
1	Residential	$140,969	$13,170	$14,892	$897	$253,963	$3,164	$177	$427,232	$130,785,046	0.3267%
2	Commerical	$7,424	$390	$612	0	$19,091	$274	0	$27,791	$57,716,181	0.0482%
3	Public Authority	$58	0	0	0	$68	$2	0	$128	$9,353,818	0.0014%
4	School	0	0	0	0	$102	0	0	$102	$10,125,430	0.0010%
5	Industrial	$87	0	$51	0	$306	$2	0	$446	$71,255,919	0.0006%
6	Mine Power	0	0	0	0	$272	$2	0	$274	$47,864,258	0.0006%
7	Public Street Lighting	0	0	0	0	$0	0	0	$0	$1,004,043	0.0000%
8	Total	$148,538	$13,560	$15,555	$897	$273,802	$3,444	$177	$455,973	$328,104,695	0.1390%

Exhibit EKW-9

Kentucky Power Company
CATV Pole Attachment Rate Calculations
for the Twelve Months ending June 30, 2005

Exhibit EKW - 10

Ln No (1)	Description (2)	FERC Acct. No. or Reference (3)		Amount (4)
	Gross Plant			
1	Poles	364		$126,864,495
2	Conductor	365		$102,420,173
3	Services	369		$31,586,290
4	Total Overhead Accounts			$260,870,958
5	Total Distribution Plant	Sec V Sch 11 Ln 15		$446,448,969
6	Total Utility Plant	Sec V Sch 11 Ln 22	$1,353,341,211	
7	Less Capital Leases	Sec V Sch 12 Ln 10	$6,683,310	$1,346,657,901
	Depreciation Reserve			
8	Total Distribution Plant	Sec V Sch 12 Ln 3		$130,847,900
9	Total Utility Plant	Sec V Sch 12 Ln 8	$443,489,466.0	
10	Capital Leases	Sec V Sch 12 Ln 10	$6,683,310.0	$436,806,156
11	Poles	(Ln 1 / Ln 5) X Ln 8		$37,182,195
12	Overhead Accounts	(Ln 4 / Ln 5) X Ln 8		$76,457,601
	Deferred Taxes			
	Total Utility Plant			
13	Accel. Amort. P. Prop.	281		$4,281,600
14	Other P. Prop.	282		$110,227,605
15	Total Deferred Taxes	Sum Accts. 281 + 282		$114,509,205
16	Poles	(Ln1 - Ln11)/(Ln7-Ln13)*15		$11,286,947
17	Overhead Accounts	(Ln4 - Ln12)/(Ln7-Ln10)*15		$23,209,305
18	Net Pole Investment	(Ln1-Ln11-Ln16)		$78,395,353
19	Net Overhead Accts.	(Ln4-Ln12-Ln17)		$161,204,052
20	Net Plant Investment	(Ln7-Ln10-Ln15)		$795,342,540
21	Appurt. Elimination Rate	Rate for Elect. Co.		15.00%
22	Year End No. of Poles			198,724
23	Net Cost of a Bare Pole	(Ln18 X (1-Ln21))/Ln22		$335.32
24	Depreciation Rate - Poles	Depreciation Study		3.64%
25	Adminstrative Expense	Sec V Wk Paper S-7 Lns 27+28		$23,819,830
26	Pole Maintenance Exp.	(Ln18/Ln19) X Ln 27		$5,432,082
27	Maint. Of Overhead Lines	593		$11,169,968
28	Opertaing Taxes			
29	Taxes Other Than Income	Sec V Schedule 9		$9,021,196
30	Income Tax - Federal	Sec V Schedule 10		$3,855,050
31	Income Taxes - Other	Sec V Schedule 10		$848,006
32	Provision for Def Inc Tax	Sec V Schedule 10		$4,949,813
33	Investment Tax Credit	Sec V Schedule 10		($1,168,684)
34	Total Operating Taxes	(Sum Lns 29 through 33)		$17,505,381
35	Depreciation Expense Factor	((Ln 24 X Ln 1) / Ln 18)		5.89%
36	Admin. Factor	(Ln 25 / Ln 20)		2.99%
37	Pole Mainten. Factor	(Ln26 / Ln Ln18)		6.93%
38	Tax Expense Factor	(Ln 34 / Ln 20)		2.20%
39	Rate of Return	Sec V Wk Paper S-2 P1		7.89%
40	Annual Cost Factor	Ln35+Ln36+Ln37+Ln38+Ln39		25.90%
41	Annual Pole Cost	Ln 40 X Ln 23		86.85
42	CATV Two Party Space %			12.24%
43	CATV Two Party Attachment Fee	Ln 43 X Ln 41		$10.63
44	CATV Three Party Space %			7.59%
45	CATV Three Party Attachment Fee	Ln 44 X Ln 41		$6.59

Kentucky Power Company
Monthly Environmental Costs
for the Twelve Months Ending June 30, 2005

Exhibit EKW-11

Ln No (1)	Month / Year (2)	Monthly Environmental Costs* (3)	Monthly Environmental Costs Per KPSC Order Dated August 7-Sep-05 (4)	Monthly Environmental Costs Included In Base Rates (5)
1	July 2004	$2,681,412	$136,800	$2,818,212
2	August 2004	$2,206,083	$136,800	$2,342,883
3	September 2004	$2,685,941	$166,364	$2,852,305
4	October 2004	$2,014,699	$167,276	$2,181,975
5	November 2004	$2,431,246	$167,276	$2,598,522
6	December 2004	$1,240,702	$167,267	$1,407,969
7	January 2005	$2,300,514	$231,270	$2,531,784
8	February 2005	$2,741,681	$262,314	$3,003,995
9	March 2005	$2,582,752	$262,314	$2,845,066
10	April 2005	$1,833,221	$262,314	$2,095,535
11	May 2005	$1,252,545	$262,314	$1,514,859
12	June 2005	$1,651,264	$262,314	$1,913,578
13	Total	$25,622,060	$2,484,623	$28,106,683

* Per ES Form 1.00 Line 3

ES FORM 1.00

AMERICAN ELECTRIC POWER - ENVIRONMENTAL SURCHARGE REPORT
CALCULATION OF E(m) and SURCHARGE FACTOR
For the Expense Month of July 2005

	CALCULATION OF E(m) E(m) = CRR - BRR	
LINE 1	CRR from ES FORM 3.00	$2,844,388
LINE 2	Brr from ES FORM 2.00	$15,785
LINE 3	E(m) (LINE 1 - LINE 2)	$2,828,603
• LINE 4	Base Month Tariff 29-3 Environmental Surcharge	$2,818,212
• LINE 5	Increase/(Decrease) of Monthly Environmental Surcharge	$10,391
LINE 6	Kentucky Retail Jurisdictional Allocation Factor, from ES FORM 3.30, Schedule of Revenues, LINE 1	64.6%
LINE 7	KY Retail E(m) (LINE 3 • LINE 4)	$6,713
LINE 8	Over/(Under) Recovery Adjustment from ES FORM	($43,922)
LINE 9	Net KY Retail E(m) (LINE 5 + LINE 6)	($37,209)
	SURCHARGE FACTOR	
LINE 10	Net KY Retail E(m) (Line 7)	($37,209)
LINE 11	KY Retail R(m) from ES FORM 3.30	$28,766,132
LINE 12	Environmental Surchage Factor for Expense Month (Line 8 / LINE 9)	-0.1294%

* New Lines Added

Effective Date for Billing: September 2005

Submitted By : ____________________

Title : Director Regulatory Services

Date Submitted : August 19, 2005

Kentucky Power Company
Rockport Extension Revenue Allocation
Using the twelve months
ending June 30, 2005 Revenues

Ln. No. (1)	Tariffs (2)	Billed Revenues (3)	Percent of Revenue (4)	Allocated $5.1 Million (5)	Twelve Months Ending June 30, 2005 kWh Sales (6)	kWh Rate All Other Customers (7)	kWh Rate CIP-TOD Customers (8)
1	Residential	$128,164,157	39.03%	$1,990,530	2,353,362,321		
2	SGS	$6,664,847	2.03%	$103,530	78,182,529		
3	MGS	$38,516,370	11.73%	$598,230	606,969,687		
4	LGS	$40,345,221	12.29%	$626,790	802,841,470		
5	OL	$4,663,358	1.42%	$72,420	40,804,873		
6	SL	$808,444	0.25%	$12,750	8,237,180		
7	MW	$354,642	0.11%	$5,610	7,195,411		
8	QP	$37,172,686	11.32%	$577,320	940,589,159		
9	CIP-TOD	$71,650,816	21.82%	$1,112,820	2,192,071,020		
10	Total	$328,340,541	100.00%	$5,100,000	7,030,253,650		
11	New Rate					$0.000824	$0.000508

Exhibit EKW-13

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY

CASE NO. 2005-00341

DIRECT TESTIMONY
OF
RANIE K WOHNHAS

ON BEHALF OF
KENTUCKY POWER COMPANY

September 26, 2005

DIRECT TESTIMONY OF
RANIE K. WOHNHAS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
CASE NO. 2005-00341

Q: Please state your name, position and business address.

A: My name is Ranie K. Wohnhas. My position is Manager, Business Operations Support, Kentucky Power Company (Kentucky Power, KPCo or Company). My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40602.

Q: Please summarize your educational background and business experience.

A: I received a Bachelor of Science degree with a major in accounting from Franklin University, Columbus, Ohio in December 1981. I began work with Columbus Southern Power in 1978 working in various customer services and accounting positions. In 1983, I transferred to Kentucky Power Company working in accounting, rates and customer services. I became the Billing and Collections Manager in 1995 overseeing all billing and collection activity for the Company. In 1998, I transferred to Appalachian Power Company working in rates. In 2001, I transferred to the AEP Service Corporation working as a Senior Rate Consultant. In July 2004, I assumed my current position.

Q: What are your responsibilities as Manager, Business Operations Support?

A: I am responsible for the coordination of the Company's financial operating plans including an operational interface with all other AEP organizations impacting KPCo results. This includes advising the President of KPCo as to the financial effect of all business activities that affect the performance of businesses within the President's responsibilities. One of my primary responsibilities is the preparation, coordination and monitoring of all the Company's yearly budgeting processes and analyses of variances to those budgets.

Q: To whom do you report?

A: I report to Kentucky Power President, Timothy C. Mosher who also is located in Frankfort, Kentucky.

Q: Have you previously testified before this Commission?

A: Yes. I have testified before this Commission in one fuel review proceeding.

Q: What is the purpose of your testimony in this proceeding?

A: I am sponsoring the Company's test year results of operations for the twelve months ended June 30, 2005 contained in Section IV. I am also responsible for nine proposed rate case adjustments to Net Electric Operating Income (NEOI) as included in Section V, Workpaper S-4.

Q: Please describe Section IV of the Company's filing.

A: Section IV of the Company's filing is the financial exhibit required by the Commission regulation in 807 KAR 5:001, Section 6. Balance sheet data is shown as of June 30, 2005 and income statement data is for the twelve months ended June 30, 2005. This complies with the ninety-day rule stipulated by the Commission in Section 6.

Q: Has the Company complied with the regulations of the Commission that require certain additional data to be filed?

A: Yes. This information has been incorporated into Section II of the Company's filing.

Q: Have you prepared any schedules or workpapers in connection with your testimony?

A: Yes. The summaries and details of the Capitalization and Rate Base amounts, and the adjustments to the "per books" results of operations that I am sponsoring are set forth in various schedules of Section V of the Company's filing. I will identify the specific schedule and page reference number in describing each summary of the proposed adjustment.

Q: What information on the summaries and adjustments are you sponsoring?

A: I am responsible for the total Company amounts shown or used to derive the KPCo retail jurisdictional amounts. Witness Wagner furnished either the KPCo retail jurisdictional amounts or the allocation factors required to calculate such amounts. Witness Wagner is responsible for the allocation methodology.

Adjustments to Rate Base

Q: Please describe the adjustments to the June 30, 2005 Rate Base balances that you are sponsoring.

A: Schedule 5 of Section V (lines 18-28) summarizes, by Rate Base component, the adjustments to Rate Base that I am supporting.

Electric Plant In Service (EPIS)- Net (Line 20)

Electric Plant In Service – Net has been decreased by $2,662,755 (Schedule 13, Column 3, Lines 9-11) to reflect inclusion of net Post In Service AFUDC and Deferred Depreciation Expense on the Hanging Rock-Jefferson 765KV line that was approved by the Commission in its Order in Case No. 9061 ($1,058,989) and to eliminate the effect of capitalized leases recorded in EPIS, for financial reporting purposes only, as required by the Financial Accounting Standards Board (FASB) No. 71 ($3,721,744).

Plant Held for Future Use – Carrs Site (Line 21)

Plant Held for Future Use has been decreased by $6,778,355 (Schedule 14, Column 3, Line 5) to remove the Carrs Site, as is supported by the testimony of Witness Wagner in his adjustments to Capitalization.

Q: Are there any other adjustments to Rate Base being proposed by the Company?

A: Yes. The other adjustments to Rate Base are summarized on Schedule 4, Page 1, Column 4 (lines 15-25) of Section V. The first adjustment is to increase EPIS – Gross by $5,484,600 for additional capital investment for service reliability purposes, which Witnesses Phillips and Wagner support. The next adjustment is to increase Prepayments by $4,083,831 to address the under-funded status of its qualified pension plan as described and supported by Witness Wagner. We also adjusted the Materials and Supplies component by $3,542,537 involving Big Sandy Plant Fuel Stock, which Witness Wagner described as an adjustment to Capitalization. The other adjustments relate to an increase in Cash Working Capital of $3,938,375, the details of which are set forth by individual Operating Expense adjustments, on Pages 3-9 of Schedule 4 of Section V.

Rate Case Adjustments to NEOI

Q: Would you describe each of the proposed Rate Case adjustments to NEOI that you are supporting?

A: Yes.

Adjustment for Postage Rate Increase (Section V, Workpaper S-4, Page 1)

The test year adjustment for postage expense annualizes the United States Postal Service (USPS) increase that is to go into effect no sooner than January 1, 2006. The USPS filed on April 8, 2005 for a 5.4 percent across the board rate increase solely to meet its legal obligation to fund a $3.1 billion escrow payment mandated by Public Law (PL) 108-18. To reflect this increased cost, the number of bills, notices, letters, etc. mailed by the Company during the test year was multiplied by the postage rate increase resulting in an increase to Operation and Maintenance (O&M) Expenses of $38,192.

Annualization of Wage Related Adjustments (Section V, Workpaper S-4, Pages 2-6)

During the test year, wage increases were granted, employee benefit plan costs escalated and payroll related taxes increased. Page 2 of Workpaper S-4 summarizes this adjustment, which increases jurisdictional O&M Expenses by $1,265,852 and Taxes Other Than Income Taxes by $67,660 to annualize the test year increases in labor and other employee related expenses incurred by the Company during the test year. Pages 3-6 of Workpaper S-4 provide further details supporting the adjustment.

The annualization of wages and salary increases, medical plan costs, life insurance costs, dental plan costs, long term disability insurance costs, Other Post Employment Benefits (OPEB) costs and savings plan costs were done to reflect the ongoing level of expense at the end of the test year period.

The annualization of Federal Insurance Contributions Act (FICA) tax expense reflects adjusting the wage and salary increases to the Old Age Survivors & Disability Insurance (OASDI) and Medicare rates and employee maximum base.

The increased pension expense of $467,590 reflects an increase in the level of pension expense to be recorded by the Company in 2005 based upon the latest actuarial information provided by the Companies' independent actuary, Towers Perrin, in accordance with FASB Statement of Financial Accounting Standards (SFAS) No. 87 (Employers' Accounting for Pensions). Pension expense increased in 2005 versus 2004 mainly as a result of an under funded minimum pension liability that was caused by actuarial losses from a decline in the discount rate and the update to the most current mortality table. The changes not only increased pension expense through amortization of pension obligation actuarial losses but also increased pension under funding, leading to the recording, in accordance with SFAS No. 87, of an additional minimum pension liability and the resulting accumulated other comprehensive income reduction to equity which Company Witness Wagner recommends be removed for ratemaking purposes.

Annualization of Property Taxes (Section V, Workpaper S-4, Page 7)

Property tax expense reflected in the test year is based principally upon the actual property investment at December 31, 2004 and property tax rates for 2004. This adjustment increases property taxes by a jurisdictional amount of $162,360 to reflect property tax expense based upon the actual property investment at the end of the test year at the latest 2005 tax rates available.

Annualized Lease Costs (Section V, Workpaper S-4, Page 14)

The test year adjustment for lease costs annualizes the current level (June 2005) of lease rental expense that increases the jurisdictional O&M Expense by $12,540.

Elimination of Advertising Expenses (Section V, Workpaper S-4, Page 15)

A review has been made of advertising expenses recorded during the test year and this adjustment eliminates $30,262 of those expenses which were promotional and institutional advertising pursuant to Commission regulation 807 KAR 5:016 Section 4(1).

Interest Expense on Customer Deposits (Section V, Workpaper S-4, Page 17)

Customer deposits have been included in this case as a reduction to the Company's Rate Base. This recognizes that customer deposits, similar to customer advances for construction, are a source of funds to the Company. Unlike customer advances for construction however, interest is paid to customers for customer deposits at a rate of 6% per annum. Consistent with the treatment of this interest allowed by the Commission in Case No. 9061 an adjustment has been made to increase test year expenses by $632,477.

AFUDC Offset (Section V, Workpaper S-4, Page 19)

The June 30, 2005 balance of Construction Work In Progress (CWIP) was used in the determination of Rate Base. Consistent with prior Commission practice for the Company, an Allowance for Funds Used During Construction (AFUDC) "offset" adjustment is being made to record AFUDC above the line. The CWIP balance was $19,336,201 at June 30, 2005 of which $3,537,800 is not subject to AFUDC. The remaining balance of $15,798,401 is subject to AFUDC and using the requested overall return of 7.89%, the annualized AFUDC is $1,246,494. The AFUDC booked during the test year was $615,862 requiring an adjustment to increase the AFUDC offset by $630,632. The Deferred Federal Income Taxes (DFIT) associated with the borrowed funds portion of the $1,246,494 is $184,674. The booked DFIT on the borrowed funds portion was $102,835. This increases DFIT by $81,839. The net effect on NEOI is a jurisdictional decrease of $81,020.

Interest Synchronization (Section V, Workpaper S-4, Page 20)

The purpose of this adjustment is to reflect in the computation of Federal and State Income Taxes included in the test period cost of service and the interest expense tax deduction that will result based upon the capital costs and capital structure included by the Company in this filing.

The annualized interest expense has been computed using long-term and short-term debt capital at a cost of 5.70% and 3.34% respectively, as proposed in the overall cost of capital. These capital components and cost rates yield a pro forma interest expense deduction of $27,607,932 (Line 7). This amount is representative of the tax deductible interest costs the Company will incur assuming the capital structure and related capital costs proposed by the Company.

The actual interest expense incurred during the test year was $29,120,772 (Line 8). In computing state income tax for the test year, the jurisdictional interest expense adjustment of ($1,221,632) (Line 11) that is the difference between the pro forma interest and actual interest is multiplied by the state income tax rate of 7.20%. This results in an increase of test year state income tax of $87,921.

Federal income taxes have been synchronized using the jurisdictional interest expense adjustment of ($1,221,632) (Line 11) that is the difference between the pro forma interest and actual interest, plus the $87,921 (Line 13) state tax effect. The net change of ($1,133,711) (Line 14) at a 35% tax rate yields an increase to FIT of $396,799 (Line 16).

Annualization of Vehicle Fuel Costs (Section V, Workpaper S-4, Page 31)

In order to properly reflect the current level of vehicle fuel costs, the Company has increased jurisdictional Operating Expense by $133,181 based on annualized June 2005 vehicle fuel costs.

Q: Does this conclude your testimony?

A: Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

COMMONWEALTH OF KENTUCKY

CASE NO. 2005-00341

COUNTY OF FRANKLIN

AFFIDAVIT

Ranie K. Wohnhas, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Ranie K Wohnhas

Ranie K. Wohnhas

Subscribed and sworn before me by Ranie K. Wohnhas this 20th day of September, 2005.

Judy K Tackett

Notary Public

My Commission Expires January 14, 2009